UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Sierra Club *et al*. v. PJM Interconnection, L.L.C.	Docket No. EL24-148-000

COMMENTS AND ANSWER OF CONSUMER ADVOCATES

Pursuant to Rule 213 of the Federal Energy Regulatory Commission's (Commission or FERC) Rules of Practice and Procedure[1] and the Commission's September 30, 2024 Notice of Complaint,[2] the Maryland Office of People's Counsel, New Jersey Division of Rate Counsel, the Office of the People's Counsel for the District of Columbia, the Office of the Ohio Consumers' Counsel, the Illinois Attorney General's Office, and the Illinois Citizens Utility Board[3] (collectively, Consumer Advocates) answer in support of the Public Interest Organizations'[4] (PIO) complaint,[5] including PIOs' request that the Commission delay the upcoming December 4, 2024 PJM Interconnection, L.L.C. (PJM) Base Residual Auction (BRA) for the 2026/2027 Delivery Year until the Commission can direct and PJM can implement tariff changes necessary to ensure just and reasonable auction rates.[6] For the reasons stated here, we urge the Commission to grant (1)

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[1] 18 C.F.R. § 385.213.

[2] eLibrary No. 20240930-3083.

[3] The Consumer Advocates individually filed doc-less motions to intervene in the above-captioned docket.

[4] PIOs are Sierra Club, Natural Resources Defense Council, Public Citizen, Sustainable FERC Project, and the Union of Concerned Scientists.

[5] Complaint of Sierra Club, Natural Resources Defense Council, Public Citizen, Sustainable FERC Project and Union of Concerned Scientists (Sept. 27, 2024), eLibrary No. 20240927-5073 (PIO Complaint or Complaint).

[6] *Id.* at 53.

PIOs' complaint and (2) additional relief in setting the just and reasonable auction rate going forward.

I. INTRODUCTION

The PIO Complaint is a welcome and necessary first step to ensuring just and reasonable rates prior to the December 4, 2024, submission of offers for the 2026/2027 BRA.

The need for prompt action concerning the BRA auction design is indisputable. In the span of one PJM base residual auction cycle, PJM capacity auction charges spiked from $2.2 billion (2024/2025 BRA) to $14.7 billion (2025/2026 BRA), an increase of $12 billion or 554%.[7] While a 554% increase in the auction clearing price is reason enough to consider implementing design changes, forecasts concerning the fast-approaching next BRA look even worse.

Absent Commission action, the December auction for the 2026/2027 Delivery Year could result in capacity charges to PJM ratepayers totaling some $37 billion. On September 27, 2024, the Organization of PJM States, Inc. wrote PJM warning that auction "flaws [identified by the PJM Independent Market Monitor (IMM)] could lead to the upcoming auction clearing at the maximum capacity price which would assign a total cost to customers of over $30 billion for the 2026/2027 Delivery Year."[8] Consistent with this warning, one expert energy market consultant has analyzed PJM market supply and

[7] PJM, 2025/2026 Base Residual Auction Report at 4, tbl.2 (July 30, 2024), https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx (PJM 2025/2026 BRA). In fact, the actual jump is even greater because the 2024/2025 auction charges were wrongly inflated by the use of an inaccurate Local Delivery Area Reliability Requirement (LDA RR) for the DPL-South zone. Use of the incorrect LDA RR artificially inflated 2024/2025 auction charges for the DPL-South zone by roughly $180 million.

[8] Comments and Motion to Lodge of the Organization of PJM States, Inc. Attach. A, OPSI Letter to PJM Board of Managers at 2 (Sept. 27, 2024), eLibrary No. 20241008-5114 (OPSI Letter).

demand fundamentals and the auction rules for the 2026/2027 BRA and projected "highly uncertain" outcomes including a "high case" scenario of the entire PJM region clearing at the new offer cap of "$696/MW-day."[9] This high case scenario would result in total capacity charges to PJM customers in the range of $37 billion.[10]

The Complaint identifies one essential tariff change to prevent a recurrence in the 2026/2027 BRA of an auction design deficiency that on its own produced generator windfalls of $4-5 billion in the 2025/2026 Delivery Year.[11] The PIOs ask FERC to exercise its Federal Power Act (FPA) section 206[12] authority and find the current auction design unjust and unreasonable and, consistent with Commission precedent and tariff rules in other RTO/ISOs,[13] modify the PJM Tariff to require generators under Reliability Must Run (RMR) arrangements to bid into the upcoming auction at a zero dollar offer price. This relief is required to protect ratepayers against excessive auction clearing prices and having to pay twice to meet same capacity need.[14] Consumer Advocates agree with the Complainants that FERC must act before the submission of bids for the 2026/2027 BRA, currently scheduled for December 4.

But the PIO Complaint understates the gravity of the BRA's design flaws and seeks unduly narrow relief. More must be done to address evident market power concerns and

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[9] Aurora Energy Research, PJM Capacity Market - 2025/2026 BRA results & outlook for upcoming auctions at 7 (Sept. 2024) (Aurora Report). A redacted and publicly available copy of the Aurora Report appears at Attach. A.

[10] The new PJM BRA offer cap price of $695.8 x 365 days x the 147,264 MW reliability requirement for the 2026-2027 BRA Delivery Year equals total charges to load of $37,400,196,288. The actual figure would depend on the amount of capacity that clears at the offer cap region wide.

[11] PIO Complaint at 1-2.

[12] 16 U.S.C. § 824e.

[13] Regional Transmission Operators/Independent System Operators (collectively, RTOs).

[14] PIO Complaint at 1-2.

ensure just and reasonable auction rates. Thus, while the Consumer Advocates support the PIO Complaint and urge the Commission to grant it as soon as possible, a subset of the Consumer Advocates will soon file a separate complaint identifying additional changes that should be made before conducting the BRA for the 2026/2027 delivery year.

PJM has suggested that the most recent BRA results will send the proper "price signal" that new investment is needed, and that the market will "respond" with new resources and, in time, a more moderate BRA auction clearing price.[15] But the evidence is to the contrary. The central purpose of PJM's Reliability Pricing Model (RPM) and forward-looking auction design is to enable new entry to compete with existing resources and thereby mitigate the ability of existing resources to exercise market power and raise prices.[16] The upcoming auction, however, presents a perfect storm of adverse market factors that impede new entry and further existing resources' exercise of market power. PJM forecasts increased demand while supply heads in the opposite direction, as further resource deactivations are scheduled. And, because of the interconnection queue moratorium, and the 24-month window between the July 30, 2024, announcement of the results of the 2025/2026 BRA and the commencement of the 2026/2027 Delivery Year, it is unlikely that significant new resources will bid into the 2026/2027 BRA.[17]

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[15] Letter from Mark Takahashi, Chair PJM Board of Managers to David S. Lapp, Maryland Office of People's Counsel, *et al.* at 2 (Sept. 19, 2024) (the 2025/2026 BRA price "signal is consistent with market fundamentals."), https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/2024/20240919-pjm-board-response-consumer-advocates-letter-re-urgent-reforms-pjm-capacity-market-re-reliability-must-run-units.ashx.

[16] *PJM Interconnection L.L.C.*, 117 FERC ¶ 61,331, P 101 (2006), *on reh'g*, 119 FERC ¶ 61, 318, *reh'g denied*, 121 FERC ¶ 61,173 (2007).

[17] PIO Complaint at 4. *See also id.* at 48-50 (and sources cited therein).

The PIOs correctly observe that "[t]he fast pace of PJM's capacity auctions and the slow pace of its interconnection queue mean that new generation is highly unlikely to be able to come online quickly enough to prevent price spikes like the one caused by PJM's most recent auction."[18] PJM has recently acknowledged that "[w]hile PJM continues to execute against the [interconnection] transition plan, concerns are growing that the construction build-out from the volume of applications has not yet materialized[.]"[19] Similarly, a recent academic survey of developers with PJM interconnection queue projects found that "PJM's increasingly lengthy interconnection process is exacerbating siting and permitting challenges and leading to knock-on delays in equipment procurement and financing decisions, suggesting the timeline for new generation in this market will likely remain long for the foreseeable future."[20] Unconstrained by new entry, existing resources will be highly incented to exercise market power. Changes in market design for the 2026/2027 BRA, including the new offer cap of $695.8/MW-day, and a more steeply vertical VRR (demand) curve[21] increase the likelihood of exorbitant and artificial auction prices, absent relief.

We therefore agree with the IMM's conclusion that the 2025/2026 BRA results "were significantly affected by flawed market design decisions" as well as "the exercise of

[18] *Id.* at 4.

[19] Ethan Howland, *PJM says 'concerns are growing' after less than 2 GW added this year*, Utility Dive (Sept. 26, 2024),https://www.utilitydive.com/news/pjm-interconnection-capacity-online-construction-shortfall-vc-renewables/728145/.

[20] Attach. B, Abraham Silverman, Dr. Zachary A. Wendling, Kavyaa Rizal, and Devan Samant, *Outlook for Pending Generation in the PJM Interconnection Queue* at 7, Columbia Center on Global Energy Policy (May 8, 2024) (Columbia Study). "Only 10 percent of developers report that any of their projects will come online within 12 months of receiving an interconnection service agreement, and most report their projects will require at least 24 months from the time they receive such an agreement to reach commercial operation." *Id.* at 7-8.

[21] *See, e.g.*, Aurora Report at 30.

market power" and thus "do not solely reflect supply and demand fundamentals."[22] Fundamentally, the likelihood that new entry will be unable to discipline the market power of existing resources—contrary to a foundational premise of PJM capacity market design—mandates that the Commission act now to ensure that all available resources must participate in the upcoming capacity market auction.

That is not currently the case and renders the existing market design unjust and unreasonable. As discussed more fully below, we strongly encourage the Commission to consider the imposition of additional remedial measures to mitigate the market power of existing resources. These would include: (1) in addition to RMR units, subjecting other currently exempt eligible resources—intermittent, storage and hydro—to PJM's capacity must offer requirement; and (2) subjecting Demand Response resources to an offer cap. While the Consumer Advocates plan to file a separate complaint expanding on these issues, the Commission is empowered to direct such necessary changes when acting on the PIO Complaint or *sua sponte*, regardless of whether the complainants requested the specific relief.[23]

Finally, to ensure that the Commission is able to implement the modifications needed to render future BRA results just and reasonable, it is essential that the Commission suspend the 2026/2027 BRA prior to the December 4 offer date. There must be adequate time for the Commission to identify and direct the necessary corrective auction measures

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[22] Independent Market Monitor for PJM, Analysis of the 2025/2026 RPM Base Residual Auction Part A at 4-5 (Sept. 20, 2024), https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf (IMM Analysis).

[23] *See Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236, P 149 & nn.273-274 (2018), *clarification denied,* 168 FERC ¶ 61,051 (2019), *on reh'g*, 171 FERC ¶ 61,034, *correcting order,* 171 FERC ¶ 61,035 (2020) and 173 FERC ¶ 61,061(2020).

and for PJM to implement them prior to the submission of offers for the 2026/2027 BRA. Consumer confidence in PJM hangs in the balance. Concerns of maintaining the auction schedule weigh little measured against the Commission's obligation to ensure that captive PJM ratepayers are protected from the market power of existing resources and do not pay tens of billions of dollars in excess capacity charges—and for a price signal to which the market is unable to timely respond.

II. COMMENTS AND ANSWER

A. Market realities render PJM's current capacity market design unjust and unreasonable.

The price excursions experienced in the BRA auction results are the combination of at least two constraints: the barrier to sufficient new entry, and the failure of the current design to require that all available sources of capacity participate in the auction.

The BRA is predicated upon the theoretical concept that new resources can and will respond to BRA capacity market price signals in sufficient time—typically the three-year period between Delivery Years—to ensure reliability and compete with existing resources.[24] The forward-looking BRA was the product of a settlement with "design features [intended to] discourage the exercise of market power and market manipulation generally. Specific mitigation rules and increased competition from new entry are the most important design elements in this regard."[25]

[24] "Since 2007, PJM's evolving capacity market has used the power of markets to commit enough resources to meet future reliability targets. The three-year-forward auction allows for competition between existing and new resources while attracting participation from across the PJM region. This design creates a wide scope for the market and provides transparent price signals to attract investment and induce less efficient resources to retire." PJM Capacity Market Promoting Future Reliability at 1 (July 16, 2024), https://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/pjm-capacity-market-promoting-future-reliability-fact-sheet.ashx.

[25] *PJM Interconnection L.L.C.*, 117 FERC ¶ 61,331, P 6.

In approving PJM's RPM, FERC found that "[t]he three-year forward market [plays an essential role in market power mitigation because it] permits competitive entry in the event that existing generators are seeking to raise prices above competitive levels."[26] Market realities no longer comport with that construct and as such it is in its present form unjust and unreasonable. The results of the 2025/2026 BRA show that sufficient new supply is not entering the market to offset retirements and load growth and competitively discipline the market power of existing resources. And the reason for the lack of new entry has little to do with capacity market auction prices. Plenty of new supply resources have sought and are seeking to enter the market but cannot get through PJM's backlogged interconnection queue. The absence of new supply does not reflect market fundamentals but an artificial constraint on supply. Thus, the 2025/2026 BRA prices are not just high but artificially so, and the Commission has long rejected market rules and prices that depart from a genuine interplay of supply and demand.[27]

Yet there is every indication that, absent market design changes, insufficient supply will be available to compete with and mitigate the market power of existing resources in the upcoming 2026/2027 BRA, resulting in excessive prices and staggering charges to

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[26] *Id.* P 101.

[27] *E.g.*, *Cal. Indep. Sys. Operator Corp.*, 171 FERC ¶ 61,220, PP 17-18 (2020) (rejecting, as not just and reasonable, tariff changes that "create an artificial constraint which raises prices for load and generation"); *Investigation of Terms & Conditions of Pub. Util. Mkt.-Based Rate Authorizations*, 105 FERC ¶ 61,218, PP 37-38 (2003) (actions creating artificial shortages are not consistent with just-and-reasonable rates); *PJM Interconnection, LLC*, 186 FERC ¶ 61,080, P 266 (2024) (noting importance of "aligning the LDA Reliability Requirement with actual reliability needs"), *reh'g denied,* 186 FERC ¶ 62,168 (2024); *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs.*, 93 FERC ¶ 61,294, at 61,998 (2000) ("While high prices in and of themselves do not make a rate unjust and unreasonable (because, for instance, underlying production prices may be high), if over time rates do not behave as expected in a competitive market, the Commission must step in to correct the situation.") (subsequent history omitted).

consumers. This is not just and reasonable. Purported market prices that "do not reflect legitimate market forces . . . fall outside the zone of reasonableness."[28]

PJM has explained that the results of the 2025/2026 BRA were driven by a "[s]ignificant decrease in overall supply from retirements (actual retirements plus must offer exceptions for future retirements),"[29] which, when combined with a decrease in new entry, resulted in a significant decline in supply offered into the capacity market from 148,945.7 MW in the 2024/2025 BRA to 135,692.3 MW in the 2025/2026 BRA.[30] Thus, while PJM raised its installed reserve margin target for the 2025/2026 BRA relative to the 2024/2025 BRA, the reserve margin for the entire RTO decreased by approximately two percentage points,[31] resulting in the lowest overall reserve margin PJM has had in the past decade.[32] Underscoring the market supply limitations, two Locational Deliverability Areas constrained in the 2025/2026 BRA, and PJM, as a whole, failed its Three-Pivotal Supplier Test,[33] resulting in the finding that *all* existing generation capacity resources have market power and, thus, the application of market power mitigation to all existing generation

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[28] *Investigation of Terms & Conditions of Pub. Util. Mkt.-Based Rate Authorizations*, 103 FERC ¶ 61,349, P 22 (2003).

[29] PJM 2025/2026 BRA at 3, tbl.1.

[30] *Id.* at 3.

[31] *Id.* (explaining that for the 2024/2025 BRA, the overall reserve margin was 20.4%, 5.7 percentage points higher than the target reserve margin of 14.7%, whereas for the 2025/2026 BRA, the reserve margin is 18.5%, a mere 0.7 percentage points higher than the target reserve margin of 17.8%.). *See also* Energy Ventures Analysis, *Results and Likely Impacts of PJM's 2025/26 Base Residual Auction* at 2 (Aug. 2024), https://www.evainc.com/wp-content/uploads/2024/08/2024_08_21-EVA-Report-on-PJM-2025-26-BRA-Results-final.pdf (Energy Ventures Analysis).

[32] PJM 2025/2026 BRA Report at 4, tbl. 2.

[33] The Three-Pivotal Supplier Test is a PJM-specific variant of the Commission's Delivered Price Test. For a given constraint, it measures the degree to which supply from the two largest suppliers and the seller under consideration is required to relieve that constraint in a given hour. *See* PJM Operating Agreement, Schedule 1, § 6.4.1(e).

capacity resources.[34] "All offered thermal, nuclear, demand response and solar capacity cleared the 2025/26 BRA."[35]

Absent relief there is every reason to expect that the immediate upcoming auction (and potentially future ones) will produce even more extreme and unreasonable outcomes. In March of this year, the IMM reported that "24 GW to 58 GW of thermal resources — or *12% to 30%* of the PJM Interconnection's installed capacity — are at risk of retiring by 2030 *without a clear source of replacement generation*."[36] Meanwhile, PJM expects its forecasted peak load to increase by approximately 2.5% each year, "driven by the development of data centers throughout the PJM footprint, combined with the accelerating electrification of transportation and industry."[37] The near term forecast for the 2026/2027 BRA is potentially dire. An international energy market consulting firm has analyzed PJM market fundamentals for the 2026/2027 BRA and found plausible that the entire PJM region could constrain,[38] subjecting ratepayers to extraordinary capacity charges in exchange for a portfolio of resources providing (by PJM's own measure) suboptimal reserve margins.

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[34] PJM 2025/2026 BRA Report at 3, tbl. 1.

[35] Aurora Report at 13.

[36] Ethan Howland, *Up to 58 GW faces retirement in PJM by 2030 without replacement capacity in sight: market monitor*, UTILITY DIVE (Mar. 18, 2024), https://www.utilitydive.com/news/pjm-coal-gas-power-plant-risk-retirement-market-monitor/710518/ (emphasis added).

[37] *See, e.g.,* PJM Interconnection, L.L.C., *PJM Publishes 2024 Long-Term Load Forecast* (Jan. 8, 2024), https://insidelines.pjm.com/pjm-publishes-2024-long-term-load-forecast/#:~:text=The%202024%20summer%20forecast%20peak%20demand%2C%20or%20load%2C,in%202039%2C%20an%20increase%20of%20nearly%2042%2C000%20MW. *See also* Aurora Report at 11.

[38] Aurora Report at 7.

PJM says that the BRA results will incent needed new generation.[39] The reality that must be acknowledged is that the cavalry—in the form of sufficient new resources required to bid into the BRA—is not coming. The 2026/2027 Delivery Year begins June 1, 2026, less than two years from now. Yet, according to a Columbia Center on Global Energy Policy study, project development in PJM is stagnating, overall project schedules are increasing in length, and "projects entering the queue today have little chance of coming online before 2030."[40] To that end, developers with projects in the queue are delaying essential steps of project development until they have an Interconnection Service Agreement (ISA), and most anticipate that once they execute an ISA it will be another two years or more before their projects enter service.[41]

Consistent with the Columbia Study's finding, Aurora Energy Research issued a report identifying only one new resource (an 800 MW gas fired unit) expected to offer into the 2026/2027 BRA.[42] Whether this very near-term prognostication will prove correct remains to be seen, but for purposes of the 2026/2027 BRA there is no reason to believe that adequate new resources will bid into the auction in sufficient quantity to compensate for unit retirements[43] and projected load growth, and thereby discipline the market power

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[39] PJM's July 30, 2024, Press Release, entitled, "PJM Capacity Auction Procures Sufficient Resources To Meet RTO Reliability Requirement, Tighter Supply/Demand Balance Drives Higher Pricing Across the Region" states:

> "The capacity auction has been a valuable tool over time to help PJM competitively secure resources to meet reliability requirements," said President and CEO Manu Asthana. "The significantly higher prices in this auction confirm our concerns that the supply/demand balance is tightening across the RTO. The market is sending a price signal that should incent investment in resources."

[40] Columbia Study at 7.

[41] *Id.* 19.

[42] Aurora Report at 26.

[43] To date, only one plant operator has withdrawn plans to deactivate and participate in the 2026/2027 BRA. Ethan Howland, *Middle River Power reverses plan to shut down 540 MW plant amid record PJM capacity*

of existing resources. The paucity of new resources likely to compete with existing resources in the upcoming auction despite the high clearing prices of the 2025/2026 BRA is antithetical to the structural premise of the BRA that the market power of existing resources will be constrained by competition from new entry.[44]

While new entry is blocked, the PJM market design exempts substantial categories of existing resources that contribute to resource adequacy, including but not limited to those operating under RMR arrangements, exerting further upward pressure on auction prices. It is uncertain whether the current BRA price excursions will change that dynamic. The Aurora Report posits that while the participation of eligible exempt resources in the 2026/2027 BRA is "[i]ncentivized by . . . high clearing prices and low capacity performance penalties," it remains "unclear how much will re-enter, if any."[45] There is a substantial risk that fleet operators who own a portfolio of resources will not bid their eligible but exempt resources into the market, expecting that the existing, non-exempt resources that are also part of their portfolios will profit even more from the higher overall clearing prices that result from this withholding. Synapse Energy Economics estimates that Talen Energy Marketing Inc.'s decision to not bid its Brandon Shores and Wagner units into the 2025/2026 BRA (resources operating under RMR arrangements and thus currently exempt from BRA participation) resulted in Talen receiving PJM revenues that were $360 million higher than they otherwise would have been had these units bid into the BRA.[46]

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*price*s, Utility Dive (Sept. 12, 2024), https://www.utilitydive.com/news/middle-river-power-retire-elgin-power-plant-pjm-interconnection/726824/.

[44] *See also* PIO Complaint at 24, 48-50 (and sources cited therein) (new entry unlikely to be sufficient to discipline PJM capacity prices and the exercise of market power by existing RMR resources in upcoming BRA auction).

[45] Aurora Report at 26.

[46] PIO Complaint, Attach. 2, Synapse Report at 8. (prepared for the Maryland Office of People's Counsel).

Under the full cost-of-service compensation structure that Talen is seeking, ratepayers would pay for the units' full cost of service net of market revenues. This structure renders the generator indifferent to the amount of market revenue it earns. A generator in that situation has no incentive to offer its capacity in the market—but every incentive to withhold it if doing so will increase the prices the generation owner will receive for other capacity resources in the owner's portfolio.

In these circumstances, where entry of new supply is functionally blocked and owners of existing resources have incentives to exercise market power by withholding them, it is imperative to adopt rules ensuring that all existing resources participate in PJM's capacity auction. Yet PJM's current tariff design fails to do so. It allows physical withholding of RMR generation and other resources (i.e., intermittent, storage and hydro resources) that are exempt from must-offer requirements. And it allows economic withholding of demand response resources that (unique among capacity suppliers) are not subject to an offer cap. The effects of these failures are magnified by other recent market-design changes that reduce the apparent supply of capacity available to PJM, including:

- PJM's recent application of an Effective Load Carrying Capacity (ELCC) accreditation to all generating resources[47]—a method it had previously applied only to variable resources[48]—which "effectively reduced the amount of accredited unforced capacity by almost 25,000 MW or 17% of the 2025/26 cleared unforced capacity."[49] The IMM estimates that this change "resulted in a 49.1 percent increase in RPM revenues, \$4,436,433,748, for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had PJM cleared the auction without locational constraints and using the prior . . . approach."[50] Significantly, the IMM calculates that the change in accreditation methodology—and *not* the failure of certain RMR resources to

[47] PJM 2025/2026 BRA Report at 3.

[48] Energy Ventures Analysis at 7-8.

[49] *Id.* at 9.

[50] IMM Analysis at 1.

participate in the auction—was the single biggest factor driving the increase in clearing price in the 2025/2026 BRA clearing price.[51]

- PJM's shift from "average" to "marginal" ELCC as part of its recently expanded application of ELCC accreditation.[52] Marginal ELCCs are typically lower than average ELCCs, as they "measure the contribution of an additional MW to reliability, which is typically below the average due to correlated outage risks and cannibalization within a technology type."[53]
- PJM's decision to use summer ratings instead of higher winter ratings for combined cycle and combustion turbine capacity accreditation, which increased RPM costs between 23% and 118% depending on how the change affected the installed reserve margin.[54]

All of these factors—and the structural market power endemic to the PJM capacity market[55]—have compound effects such that the current market design is unjust and unreasonable and must be rectified to protect against existing resources' exercise of market power. The IMM Analysis[56] lays out the problem succinctly.

> Based on the data and this review, the [Market Monitoring Unit] concludes that the results of the 2025/2026 RPM Base Residual Auction were significantly affected by flawed market design decisions including PJM's ELCC approach and by the exercise of market power through the withholding of categorically exempt resources and high offers from demand resources. The BRA prices do not solely reflect supply and demand fundamentals but also reflect, in significant part, PJM decisions about the definition of supply and demand.

[51] *Cf.* IMM Analysis at 8 (estimating a 49.1 percent increase in capacity market revenues driven by the ELCC accreditation change) *with* IMM Analysis at 9 (estimating a 41.2 percent increase in capacity market revenues driven by the exclusion of the capacity of certain RMR resources).

[52] Aurora Report at 20.

[53] *Id*.

[54] IMM Analysis at 10-11.

[55] "The capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership. Market power is and will remain endemic to the structure of the PJM Capacity Market." IMM Analysis at 3.

[56] IMM Analysis at 4-5.

In these circumstances, there are more than ample grounds to impose the relief sought in the PIO Complaint. But more is required in order to rectify the evident flaws in the BRA design.[57]

B. A complement of mitigation measures must be implemented to ensure just and reasonable auction rates for the 2026/2027 BRA.

Incident to its section 206 authority, the Commission enjoys considerable discretion in "determin[ing] the just and reasonable rate . . . , to be thereafter observed and in force."[58] The Commission can grant a complaint in part, finding the existing rate unjust and unreasonable, but act *sua sponte* to determine the appropriate just and reasonable rate to be observed thereafter.[59] Given the unlikelihood that new entry will adequately discipline the market power of existing resources, changes must be imposed. There is insufficient time for queue reform to solve the problem of inadequate new entry in the upcoming BRA. Consistent with the IMM's recommendations, the Commission should instead[60] direct PJM to reform the capacity market rules to reflect the reality that additional resources, including but not limited to RMR resources, exist in the region to reliably serve load in the Delivery Year even though they are not currently required to offer into the auction. This will increase the amount of existing supply that must offer into and compete in the 2026/2027 BRA. The Commission also should impose an offer cap on demand resources to mitigate strategic bids intended to increase market clearing prices.

[57] Again, to the extent the Commission requires a separate section 206 filing in order to impose relief outside the four corners of the PIO complaint, Consumer Advocates intend to file this complaint shortly.

[58] 16 U.S.C. § 824e(a).

[59] *See, e.g.*, *Calpine Corp. v. PJM Interconnection L.L.C.*, 163 FERC ¶ 61,236, PP 6-7.

[60] Queue reform may be appropriate as a longer-term remedy.

The PIO Complaint is consistent with these precepts in targeting one subset of eligible but exempt resources: units under RMR arrangements. Unlike in other RTOs, RMR units in PJM are not required to offer into PJM's BRA.[61] As a result, while RMR resources are compensated to provide system reliability and can be called on by PJM to do so, they do not have an obligation to participate in the BRA. Consumer Advocates agree that this is a significant flaw in PJM's market design, creating a mismatch in the actual supply available to serve load in comparison to the amount of load that must be served. The result is that customers are forced to pay twice to satisfy the same capacity need—i.e., once to compensate the RMR unit, and then again to secure a like amount of replacement capacity in the BRA—at exorbitant cost. The Commission has repeatedly held with respect to other RTO/ISOs that it is unjust and unreasonable for ratepayers to pay twice to meet the same need and, to avoid that outcome, that RMR units must participate in the capacity as price takers at a zero dollar offer.[62]

It is no longer just and reasonable to exempt RMR units in PJM from offering into the BRA. As the IMM estimates, the exclusion of certain RMR resources from "the supply curve at $0 per MW-day resulted in a *41.2 percent increase* in RPM revenues for the 2025/2026 [BRA] compared to what RPM revenues would have been had the capacity of the RMR resources been included in the supply curve at $0 per MW-day."[63] Using slightly different modelling assumptions, Synapse Energy Economics has determined that the failure of these RMR units to bid into the 2025/2026 BRA increased costs to ratepayers by

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[61] *See, e.g.,* PIO Complaint at 7-8; PJM Open Access Transmission Tariff, Attach. DD § 6.6(g).

[62] PIO Complaint at 10-16. *See also N.Y. Indep. Sys. Operator, Inc.* 161 FERC ¶ 61,189, P 55 (2017); *New York Indep. Sys. Operator, Inc.* ("*NYISO I*"), 155 FERC ¶ 61,076 at PP 82–83 (2016); *ISO New England, Inc.*, 165 FERC ¶ 61,202 at PP 82–83 (2018).

[63] IMM Analysis at 9 (emphasis added).

$5 billion.[64] Whatever the propriety of exempting RMR units from BRA participation in the past,[65] current market conditions mandate a new rule. Requiring RMR units to bid into the 2026/2027 BRA at $0 per MW-day will: prevent ratepayers from having to pay twice for the same capacity need; and mitigate the market power of both the RMR units and other existing resources that will have to compete with this supply in the auction.

While Consumer Advocates therefore support reforming the PJM Tariff's treatment of RMR resources, more must be done to address the factors artificially depressing supply. The PJM Tariff's categorical exemption of "intermittent and capacity storage resources, including hydro," from the must offer requirement applicable to all other capacity resources (except for Demand Response resources)[66] also artificially decreases supply for the same reason as the exclusion of the RMR units. [67] The IMM identifies these resources' exemption as increasing "clearing prices above the competitive level."[68] The Commission must direct PJM to modify the tariff and require these currently exempt units to bid into the BRA.

There is good reason to do so. Requiring this additional supply to bid into the auction should limit the market power of existing resources by increasing competition and mitigate the withholding of eligible resources. The owners of intermittent resources have opposed a must offer obligation due to the risk of incurring capacity performance

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[64] PIO Complaint, Attach. 2, Synapse Report.

[65] PJM has opposed the imposition of a must offer obligation on RMR units fearing that this will cause the unit owners to stop operating the units altogether. With respect to a fleet operator such as Talen, it is against its economic interest to do so and thereby jeopardize the PJM system. In any event, the Department of Energy would likely exercise its FPA section 202(c) authority to prevent such a result and FERC would determine the applicable rate for such service.

[66] IMM Analysis at 5.

[67] *Id.* at 3.

[68] *Id.* at 3.

penalties.[69] As a practical matter, that risk is substantially attenuated in the 2026/2027 BRA because "[many areas] of PJM [will have] $0 Net Cone for 2026/2027, removing Capacity Performance penalty risk."[70] Regardless, Consumer Advocates agree with the IMM that the tariff should be modified to exempt intermittent units from capacity performance penalties going forward.[71]

Even beyond addressing the factors artificially decreasing supply, the IMM's analysis also emphasizes the importance of reforming aspects of PJM's Tariff that allow resources to exercise market power when conditions are tight, as they were in the 2025/2026 BRA and are expected to be again in the upcoming BRA. For instance, the IMM identifies as a problem the lack of an offer cap for Demand Response resources, which, when these resources are pivotal, allows them to exercise market power and increase "clearing prices above the competitive level."[72] The IMM highlights owners of capacity portfolios that include both Demand Resources and resources with a must offer requirement as particularly poised to exercise market power.[73] Similarly, owners of capacity portfolios that include categorically exempt resources as well as resources with a must offer requirement may be tempted to withhold so as to artificially increase clearing prices.[74] As discussed above, these potential exercises of market power are of grave

[69] IMM Analysis at 8.

[70] Aurora Report at 29.

[71] IMM Analysis at 8.

[72] *Id.* at 3.

[73] *Id.*at 4.

[74] *Id.* at 5.

concern, given that PJM, as a whole, failed its Three-Pivotal Supplier Test, resulting in the finding that *all* existing generation capacity resources have market power.[75]

There is no reason to believe the unjust and unreasonable outcome of the 2025/2026 BRA is an aberration. On the contrary, as shown in Part II.a, above, there is reason for concern that the situation will worsen as demand increases while supply continues to be artificially constrained. Given these realities, there is a serious risk—if not likelihood—that the limited relief provided by a $0 per MW-day must-offer requirement for RMR resources will be insufficient. Rather, comprehensively mitigating the market power of existing resources, which under current conditions cannot be disciplined adequately by new entry, is necessary to protect consumers and restore confidence in the integrity of the PJM markets.

C. Delay of the BRA is necessary to ensure adequate time to identify, direct, and implement the necessary corrective auction measures.

The Commission has "broad discretion to determine when and how to hear and decide the matters that come before it."[76] Here, fewer than 8 weeks remain before the December 4 offer date for the 2026/2027 BRA. That is not enough time to allow PJM to implement even the more limited reforms PIOs request, let alone the additional reforms needed to prevent a recurrence of the 2025/2026 BRA results. The PIOs request a delay of the auction.[77] And PJM has filed a motion seeking a delay of the PJM 2026/2027 BRA for approximately six months.[78] Consumer Advocates support such delay and urge the

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[75] PJM 2025/2026 BRA Report at 3, tbl.1.

[76] *Tenn. Valley Mun. Gas. Ass'n. v. FERC*, 140 F.3d 1085, 1088 (D.C. Cir. 1998).

[77] PIO Complaint at 53.

[78] Motion of PJM Interconnection L.L.C. to Delay the Reliability Pricing Model Auctions Beginning with the December, 2024 Base Residual Auction for Delivery Year 2026/2027 Through the 2029/2030 Delivery

Commission to grant PIOs' and PJM's requests to delay the upcoming auction expeditiously.

The need for a delay is clear. The Commission's "first and foremost duty" under the FPA "is to protect consumers from unjust and unreasonable rates."[79] Consistent with that purpose, the FPA obligates FERC to modify *any* filed rate "whenever" it finds that rate to be unjust, unreasonable, or unduly preferential.[80] "[I]f FERC sees a violation of [the just and reasonable] standard, it must take remedial action."[81] That "paramount"[82] and mandatory[83] duty persists no matter whether the rate was set by contract, tariff, or tariff-based auction.[84]

Year, Request for Expedited Action and Order by November 8, 2024, and Request for Shortened 7-Day Comment Period 5 (Oct. 15, 2024), eLibrary No. 20241015-5541.

[79] *Morgan Stanley Cap. Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cnty.*, 554 U.S. 527, 551 (2008). *See also Atl. Refin. Co. v. Pub. Serv. Comm'n of N.Y.*, 360 U.S. 378, 388 (1959) (FPA's sister, the Natural Gas Act, was "framed as to afford consumers a complete, permanent and effective bond of protection from excessive rates and charges."); *Nat'l Ass'n for Advancement of Colored People v. Fed. Power Comm'n*, 520 F.2d 432, 438 (D.C. Cir. 1975) ("Commission's primary task . . . is to guard the consumer from exploitation . . . ."). *Xcel Energy Servs., Inc. v. FERC*, 815 F.3d 947, 952 (D.C. Cir. 2016) ("It is long-established that the '[primary aim of the FPA] is the protection of consumers from excessive rates and charges.'") (internal citations omitted).

[80] 16 U.S.C. § 824e(a).

[81] *FERC v. Elec. Power Supply Ass'n*, 577 U.S 260, 277 (2016).

[82] *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332, 344 (1956) (Even rates set by contract remain "fully subject to the paramount power of the Commission to modify them when necessary in the public interest").

[83] *FERC v. Elec. Power Supply Ass'n*, 577 U.S. at 277; *New Eng. Power Generators Ass'n v. FERC*, 707 F.3d 364, 366 (D.C. Cir. 2013) ("[FERC] must ensure the rates charged for electric generation capacity are 'just and reasonable.'"); *NextEra Energy Res., LLC v. FERC*, 898 F.3d 14, 21 (2018) ("The Commission must 'protect[] . . . consumers from excessive rates and charges.'") (citation omitted).

[84] *NRG Power Mktg. v. Me. Pub. Utils. Comm'n*, 558 U.S. at 176 (remanding to decide what standard FERC should apply on review of "auction rates"); *New Eng. Power Generators Ass'n v. FERC,* 707 F.3d at 366 (considering, on appeal after remand, the standard governing "FERC review[] [of] rates resulting from an auction process"); *Pub. Citizen*, 7 F.4th 1177, 1196-98, 1200 (2021) (remanding for FERC to review whether "the results of the 2015 [MISO] Auction for Zone 4 were 'just and reasonable'" something called into question there—as here—by the "evidentiary record and the Commission's own findings").

Delaying the auction accords with Commission precedent.[85] Indeed, the Commission delayed the BRA as recently as last year so as to afford PJM sufficient time to implement capacity market rule enhancements prior to the 2025/2026 BRA.[86] In that instance, PJM recognized that "[g]iven that the purpose of PJM's capacity auctions is to provide long-term price signals to ensure capacity sufficient to maintain resource adequacy at just and reasonable rates," where the auction rules "may be unjust and unreasonable and require change, it does not appear reasonable to continue to lock in resources on a forward basis to such provisions[.]"[87] The same reasoning applies now with respect to the 2026/2027 BRA.

And, in its 2023 order authorizing PJM's requested delay, the Commission recognized that the "scope and magnitude of the capacity market related reforms" contemplated "provide sufficient justification. . . to delay the auctions," particularly in conjunction with the probability that, in the absence of delay, "market participants would be participating in auctions in the face of significant uncertainty regarding critical rules governing their capacity supply obligations in the relevant delivery year[.]"[88] Although not necessarily of the same "scope and magnitude,"[89] the suggested reforms Consumer Advocates have identified above will have a significant effect on capacity market

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[85] *See, e.g., PJM Interconnection, L.L.C.,* 177 FERC ¶ 61,050 (2021); *PJM Interconnection, L.L.C.*, 183 FERC ¶ 61,172, P 37 (2023).

[86] *See, e.g.,* PJM Interconnection, LLC, Section 205 Filing to Delay Upcoming RPM Auctions at 1, 4, Docket No. ER23-1609-000, (Apr. 11, 2023), eLibrary No. 20230411-5057 (Auction Delay Filing); *PJM Interconnection, L.L.C.*, 183 FERC ¶ 61,172 (2023) (accepting the Auction Delay Filing). The 2025/2026 was subsequently delayed even further. *FERC Sets New Date for PJM 2025/2026 Capacity Auction*, INSIDE LINES (Feb. 26, 2024), https://insidelines.pjm.com/ferc-sets-new-date-for-pjm-2025-2026-capacity-auction/.

[87] Auction Delay Filing at 1, 4.

[88] *PJM Interconnection, L.L.C.*, 183 FERC ¶ 61,172, P 37 (2023).

[89] *Id.*

outcomes. And as multiple complaints challenging the justness and reasonableness of PJM's current auction rules are expected (including the complaint that a subset of the Consumer Advocates anticipate filing later shortly), the scope and magnitude of the relief sought may expand.

Most importantly, absent delay, there is a real risk that PJM consumers could be saddled with tens of billions of dollars in excess capacity charges. To avoid that potential, the Commission should delay the auction for six-months, consistent with PJM's anticipated request, to ensure that there is adequate time for the Commission to identify and direct the necessary corrective measures and for PJM to implement them prior to the submission of offers for the 2026/2027 BRA.

CONCLUSION

WHEREFORE, for the foregoing reasons, Consumer Advocates respectfully requests that the Commission: (1) grant the PIO Complaint; (2) identify and direct the necessary corrective auction measures, as discussed in this answer; and (3) delay the 2025/2026 auction prior to the December 4, 2024 offer date for approximately 6 months to allow time for the implementation of necessary reforms.

Respectfully submitted,

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October 17, 2024

ATTACHMENT A

Aurora Energy Research

PJM Capacity Market -2025/2026 BRA results & outlook for upcoming auctions

PJM Capacity Market—
2025/2026 BRA results & outlook for upcoming auctions

September 2024

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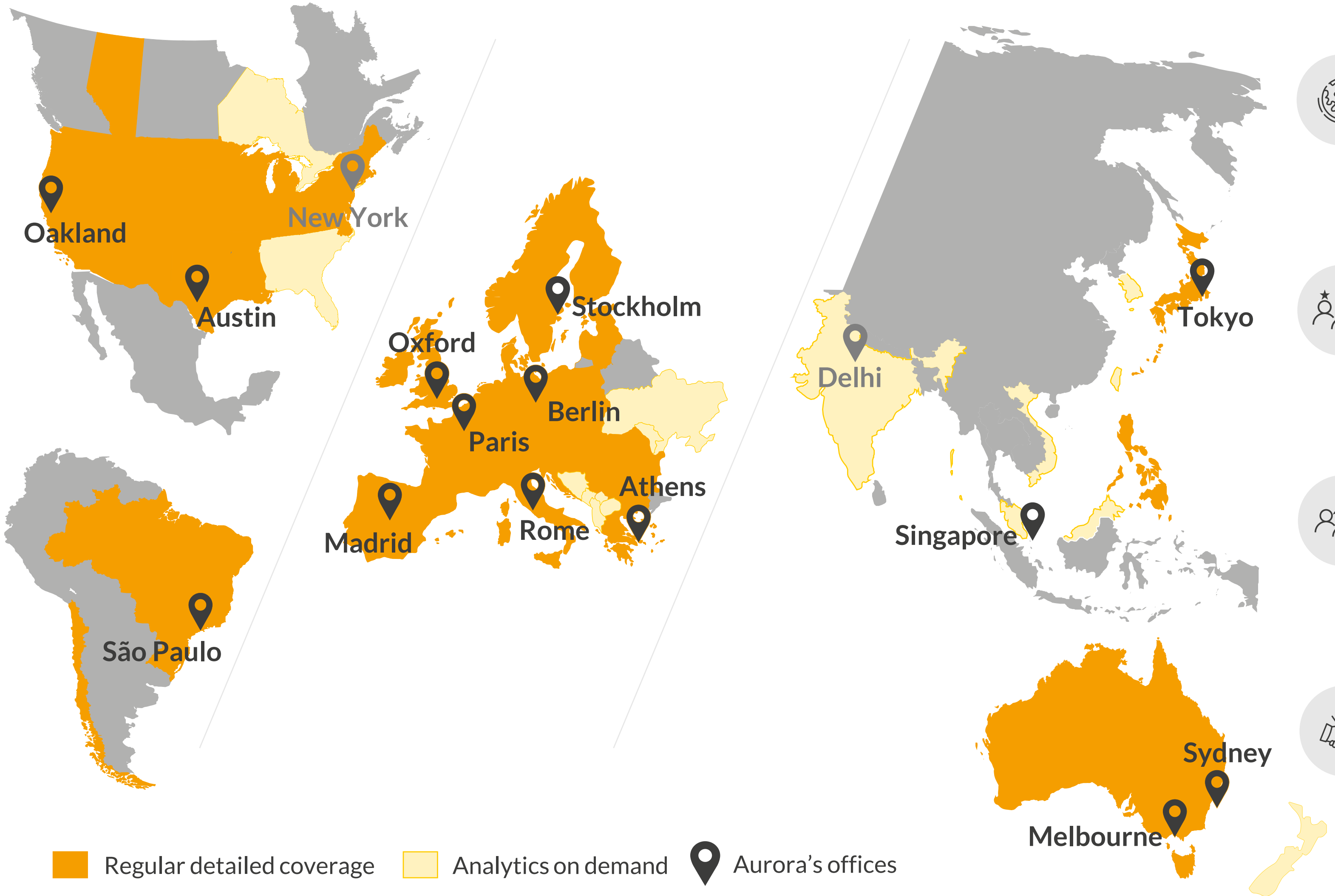

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Source: Aurora Energy Research

Unique, proprietary, in-house modelling capabilities underpin Aurora's superior analysis

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5 Integrated Models

- Global Commodities (AER-GLO)
- Hydrogen (AER-HY)
- Gas (AER-GAS)
- Power markets (AER-ES)
- Nodal/network model (AER-EN)

INPUTS

- Technology
- Policy
- Demand
- Commodity prices[1]
- Weather patterns

Dispatch model

- ½ hourly or hourly
- Iterative modelling
- Dynamic dispatch of plant
- Endogenous interconnector flows

Continuous iteration until an equilibrium is reached

Investment decisions module

- Capacity market modelling
- Capacity build / exit / mothballing
- IRR / NPV driven
- Detailed technology assessments

OUTPUTS

- Capacity mix
- Generation mix
- Wholesale & imbalance prices
- Capacity market prices
- Profit / Loss and NPV
- Electric vehicle charging

ADDITIONAL INPUTS

- Network snapshot - existing & future
- Nodal load map
- Nodal generation map

OUTPUTS

- Power flows & losses
- Nodal prices / loss factors

Up to 70	c. 85k	~15k	50+	Quarterly updates
specifications modelled for each plant	investment hours on modelling capabilities	model runs per week	strength of modelling team globally	through subscription research

1) Gas, coal, oil and carbon prices fundamentally modelled in-house with fully integrated commodities and gas market model

Source: Aurora Energy Research

Aurora is the market leader in complex transaction support involving flexible and renewable assets accessing multiple revenue streams

Non-comprehensive project examples

Battery generation

- Buy-side advisor for Engie's successful acquisition of Broad Reach Power
- Sell-side advisor for Black Mountain on ~1.5 GW asset sales to UBS Asset Management, Cypress Creek Renewables, Brookfield Renewable, & East Point Energy
- Siting strategy analysis for battery developer to inform build locations and project valuation
- Buy-side advisor on multiple equity transactions for over 1.5 GW of battery storage projects across ERCOT and CAISO, including nodal modelling, ancillary service price forecasts, and solar/wind + storage co-location analysis

Strategic

- Debt case scenario analysis for large pension fund to inform investing and lending decisions
- Downside scenario modelling for international bank to inform debt sizing
- Pricing and PPA analysis for publicly listed data center company

Renewable generation

- Buy-side advisor for Boralex's acquisition of 840 MW of onshore wind from Blackrock, including nodal pricing, basis risk, and curtailment
- Buy-side financing for 470 MW solar project in ERCOT by SocGen
- Asset-specific valuation of two wind and solar projects totalling 540 MW for infrastructure fund including nodal forecasting and curtailment
- Asset valuation for a large pumped hydro plant participating in the CAISO wholesale and ancillary markets

Thermal generation

- Modelling of proposed ERCOT market reforms (e.g. dispatchable energy credits) for project developer
- Asset valuation for lender for two existing CCGT projects in ERCOT and WECC
- Sell-side advisory for 400 MW OCGT peaking plant in West Texas for large utility
- Analysis of Biden's Clean Electricity Standard design for one of US largest utilities, to engage with White House on the role of gas CCS in the energy transition

Source: Aurora Energy Research

Get in touch with us!

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Reach out for any follow-up questions or to continue the conversation!

Executive Summary

- PJM's **2025/26 BRA** took place in July 2024 and cleared at historically high levels: **$270/MW-day** for the RTO and MAAC; the auction cap for BGE (**$466/MW-day**) and Dominion (**$444/MW-day**)—which rejoined the capacity market after four delivery years as an FRR region, and was modeled as an LDA for the first time.
- These high prices were driven by:
  - Higher demand: +8GW ICAP[1] reliability requirement (compared to the 2024/25 BRA)
  - Lower supply: -4GW ICAP[1] offered (compared to the 2024/25 BRA)
  - PJM's CIFP reforms, implemented for the first time, which raised individual bids by lowering capacity accreditation
- For the **2026/27 BRA**, taking place in December 2024, Aurora considers the outcome highly uncertain: from $100/MW-day (low case) to $696/MW-day (high case), with ~$250/MW-day a p50 expectation. Key factors impacting the 2026/27 BRA relative to the previous auction include:
  - A significantly steeper VRR curve, causing sharply increased price sensitivity compared to previous auctions, raising outcome uncertainty.
  - Higher demand: +3GW UCAP reliability requirement, which could cause a $696/MW-day clearing price (barring supply increases).
  - A strong incentive for increased supply, due to (i) expected higher clearing prices and (ii) effectively removed capacity performance penalties in >50% of PJM, due to a $0/MW-day Net CONE. The extent of supply increases is highly uncertain, but could come from withheld capacity in the 2025/26 BRA (~6GW), DR additions, bidders switching from seasonal to annual bids, or new capacity.

1) Installed capacity. Structural changes between the 2024/25 and 2025/26 BRAs make a comparison in GW UCAP (unforced capacity)—the market's native unit—meaningless.

Sources: Aurora Energy Research, PJM

Agenda

I. 2025/26 BRA: results & drivers

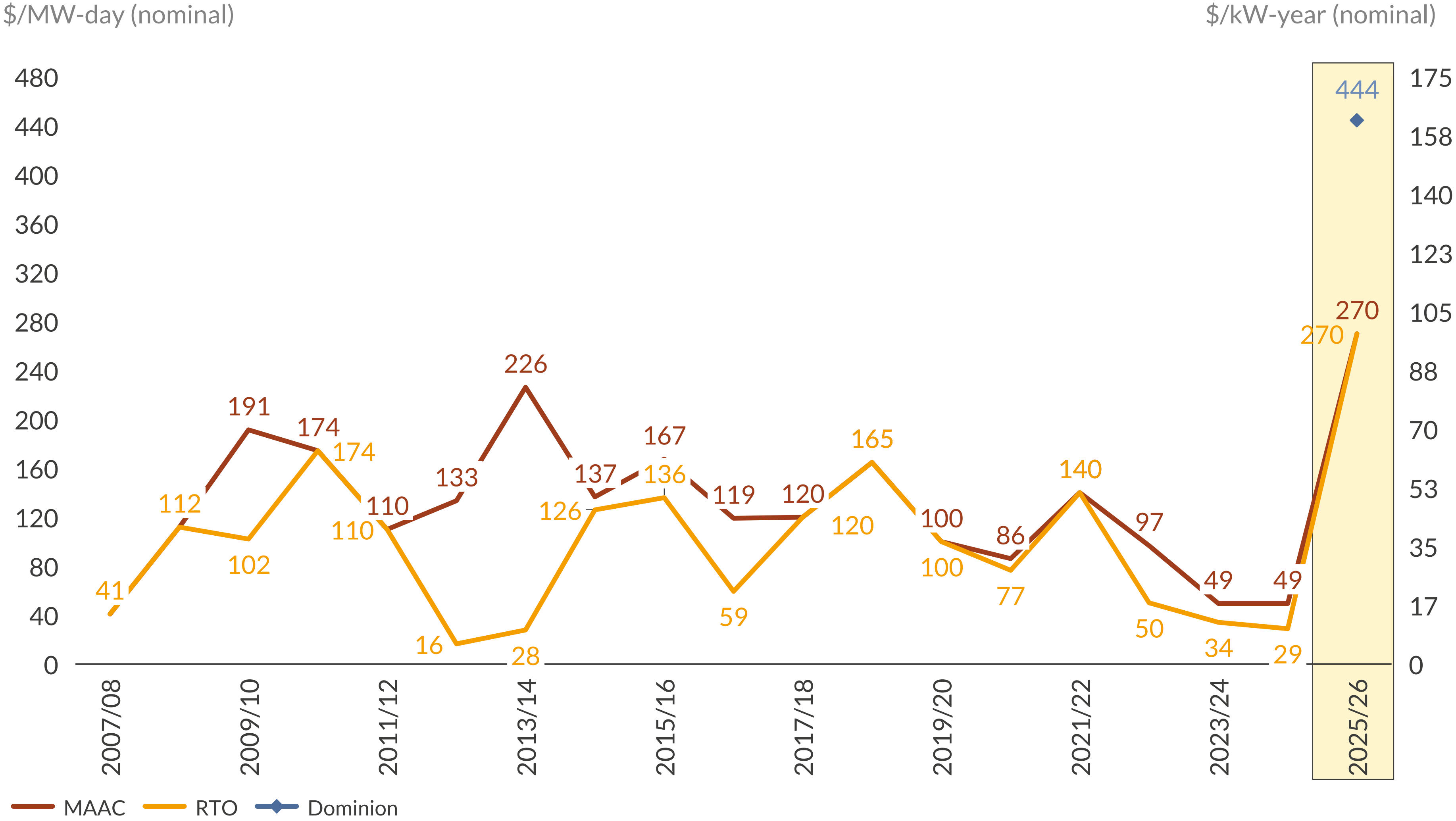
II. CIFP capacity market reforms

III. 2026/27 BRA: parameters, drivers, & expectations

IV. Long-term forecast

Results | The 2025/26 BRA cleared at $270/MW-day, a record for PJM's capacity market, with Dom clearing at its $444 price cap

PJM Base Residual Auction (BRA) clearing price for RTO and selected LDAs



1) The first delivery year for which PJM held a capacity auction was 2007/08. 2) LDA auction target capacities take existing capacity and capacity transfer objectives (CETO) into account.

Sources: Aurora Energy Research, PJM

RTO

- The Base Residual Auction (BRA) for the 2025/26 delivery year cleared RTO-wide at **$269.92/MW-day**, the highest in the 19-year history of PJM's capacity market.[1]

Dominion

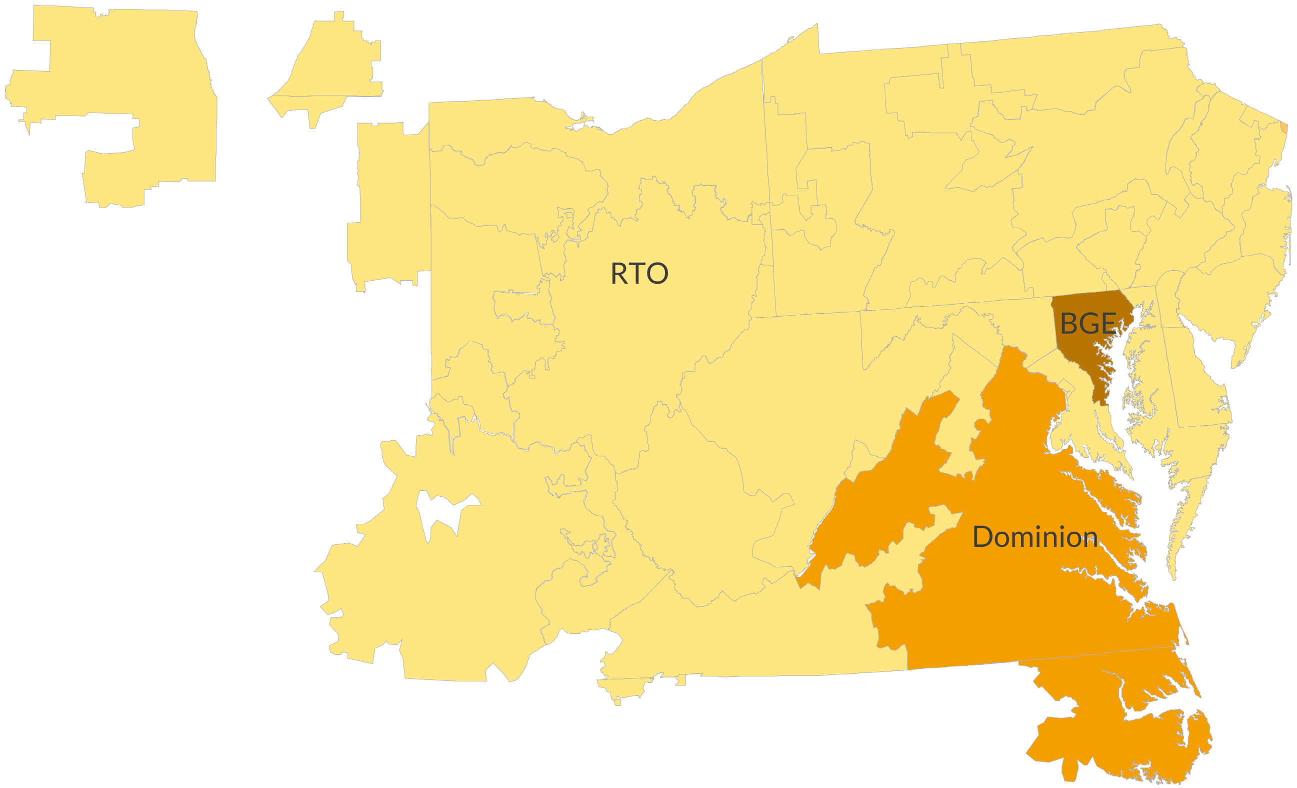
- Dominion, which re-entered the capacity market for the 2025/26 BRA, is one of the two constrained Locational Deliverability Areas (LDAs) in the 2025/26 BRA, clearing well above the RTO at **$444.26/MW-day.**
- LDAs account for transmission constraints across PJM and have individual procurement targets.[2]

MAAC

- MAAC, which has historically been a constrained LDA, cleared at the same level as the rest of the RTO in the 2025/26 BRA.

Results | Nearly all of PJM-RTO cleared at $270/MW-day—10x the last BRA's price—with BGE rising to $466 and Dominion to $444/MW-day

2025/26 BRA clearing prices and constrained LDAs



2025/26 BRA clearing price	RTO	Above RTO (constrained LDA)	
$/MW-day	269.92	444.26	466.35
($/kW-year)	(98.87)	(162.15)	(170.21)

Parent-child LDA relationship[2]

Clearing price for RTO and all constrained LDAs[1]

$/MW-day

	2024/25 BRA	2025/26 BRA
Rest of RTO	$28.92	$269.92
DEOK	$96.24	$269.92
Dominion	-	$444.26
MAAC	$49.49	$269.92
EMAAC	$54.95	$269.92
BGE	$73.00	$466.35
DPL-South	$90.64	$269.92
Total cost	$2.2bn	$14.7bn

- The RTO clearing price was ~10x higher in the 2025/26 BRA than the 2024/25 BRA.
- 2 LDAs, Dominion and BGE, were constrained in this BRA, down from 5 in the previous auction. Although MAAC cleared at the same price as the rest of RTO, it still cleared at a substantially higher price than in the last BRA.
- Total cost increased by ~$12.5bn from the last auction, primarily due to the significant increase in RTO clearing price.

1) Constrained LDAs are those with a price above their immediate region parent. For example, BGE was constrained in the 2025/26 BRA because it cleared above the RTO price. 2) Shown for each constrained LDA is the (grand)parent region responsible for all intermediate regions' prices.

Sources: Aurora Energy Research, PJM

Drivers | Supply decreases, load growth, Dominion's capacity market re-entry, and CIFP rule changes all contributed to record-high clearing prices

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Factors contributing to the 2025/26 BRA's high clearing prices

		Impact on Clearing Prices
Supply decreases	▪ Due to retirements and modestly lower Demand Response participation, supply eligible to offer into the capacity market declined by 6.5GW[1] from the 2024/25 BRA to the 2025/26 BRA. ▪ Extremely limited new generation is expected to come online prior to the start of the 2025/26 delivery year, particularly for resource types with higher ELCCs, such as dispatchable generation and offshore wind. In total, only 110MW of unforced capacity (UCAP) from new generation cleared the 2025/26 BRA.	↑↑
Demand growth	▪ Driven by data center demand, PJM forecasted peak load increased by 2.2% from 2024/25 to 2025/26, from 150.6GW to 153.9GW.	↑
Dominion rejoining the capacity market	▪ Prior to the 2025/26 BRA, the Dominion LDA primarily satisfied its capacity obligation through an FRR[2] plan outside of the PJM capacity market. Its entry into the capacity market for the 2025/26 delivery year added ~22GW to the RTO UCAP reliability requirement.[3] ▪ However, the generation resources previously used to satisfy Dominion's FRR obligations contributed only ~17GW UCAP of supply, 5 GW below the amount added to the reliability requirement.[3] With Dominion back in the capacity market, this imbalance contributed to the RTO-level supply-demand tightness.	↑
CIFP rule changes	▪ The introduction of a marginal capacity accreditation methodology decreased ELCCs[4] for most resource classes, and therefore UCAP supply. However, the impact of this change was partially offset by a corresponding reduction in the UCAP reliability requirement. ▪ Updates to PJM's approach to modeling reliability risk contributed to an increase in the Installed Reserve Margin (IRM) from 14.7% in the 2024/25 BRA to 17.8% in the 2025/26 BRA.	↓/↑

1) Measured in ICAP (Installed Capacity) terms. 2) Fixed Resource Requirement. 3) Aurora estimate based on data released by PJM. 4) Effective Load Carrying Capability.

Sources: Aurora Energy Research, PJM

Supply-demand | 2025/26 BRA conditions were much tighter than the previous auction: excess supply offered fell from 16 to 3GW ICAP

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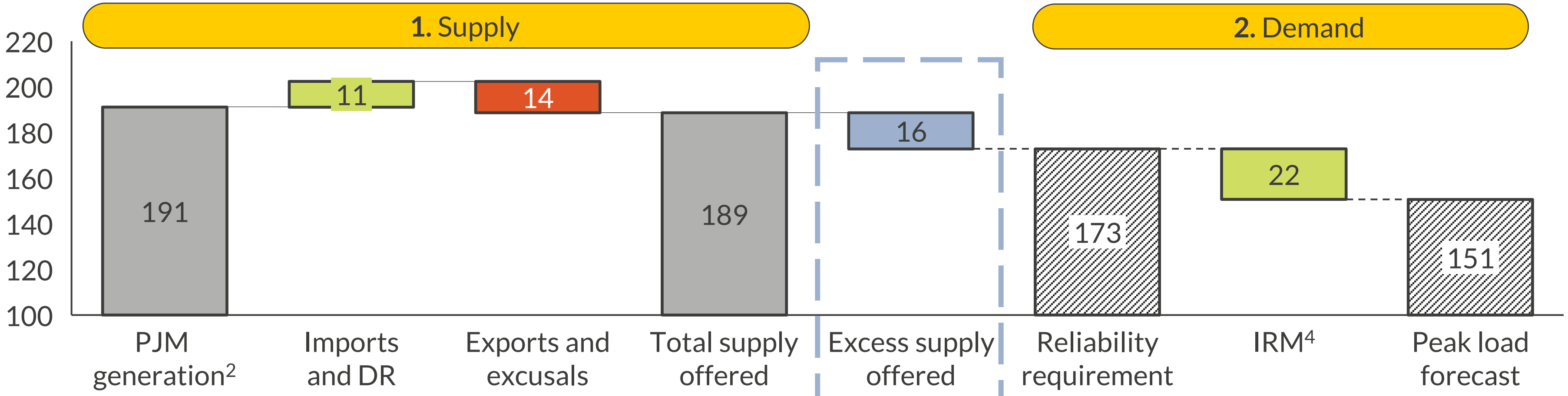
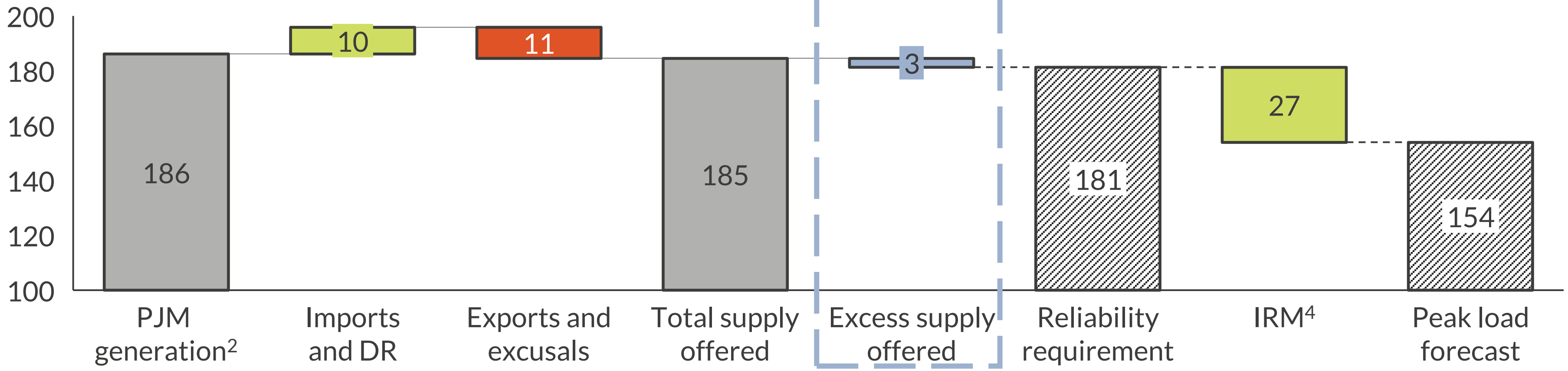
2024/25 BRA supply and demand
GW ICAP



2025/26 BRA supply and demand
GW ICAP



- Given the dramatic change in calculation of UCAP between the 2024/25 and 2025/26 BRA, ICAP[1] values provide the most apt comparison between supply and demand conditions between auctions.

1. Total supply offered into the BRA (or committed via an FRR plan) declined from 189GW to 185GW, driven by retirements and modestly lower DR[3] participation.
2. Total demand, as reflected by the reliability requirement, increased from 173GW to 181GW, due to:
   - Peak load growth from 151GW to 154GW, driven primarily by data center demand.
   - IRM[4] increase from 14.7% to 17.8%, driven primarily by changes to PJM's reliability risk modeling.

1) Installed capacity. While PJM's capacity market procures Unforced Capacity (UCAP), results are presented in ICAP terms due to substantial changes in PJM's computation of UCAP between the 2024/25 and 2025/26 auctions. 2) Including Fixed Resource Requirement (FRR) capacity. 3) Demand response. 4) Installed Reserve Margin.
Sources: Aurora Energy Research, PJM

Supply-demand | All offered thermal, nuclear, demand response and solar capacity cleared the 2025/26 BRA

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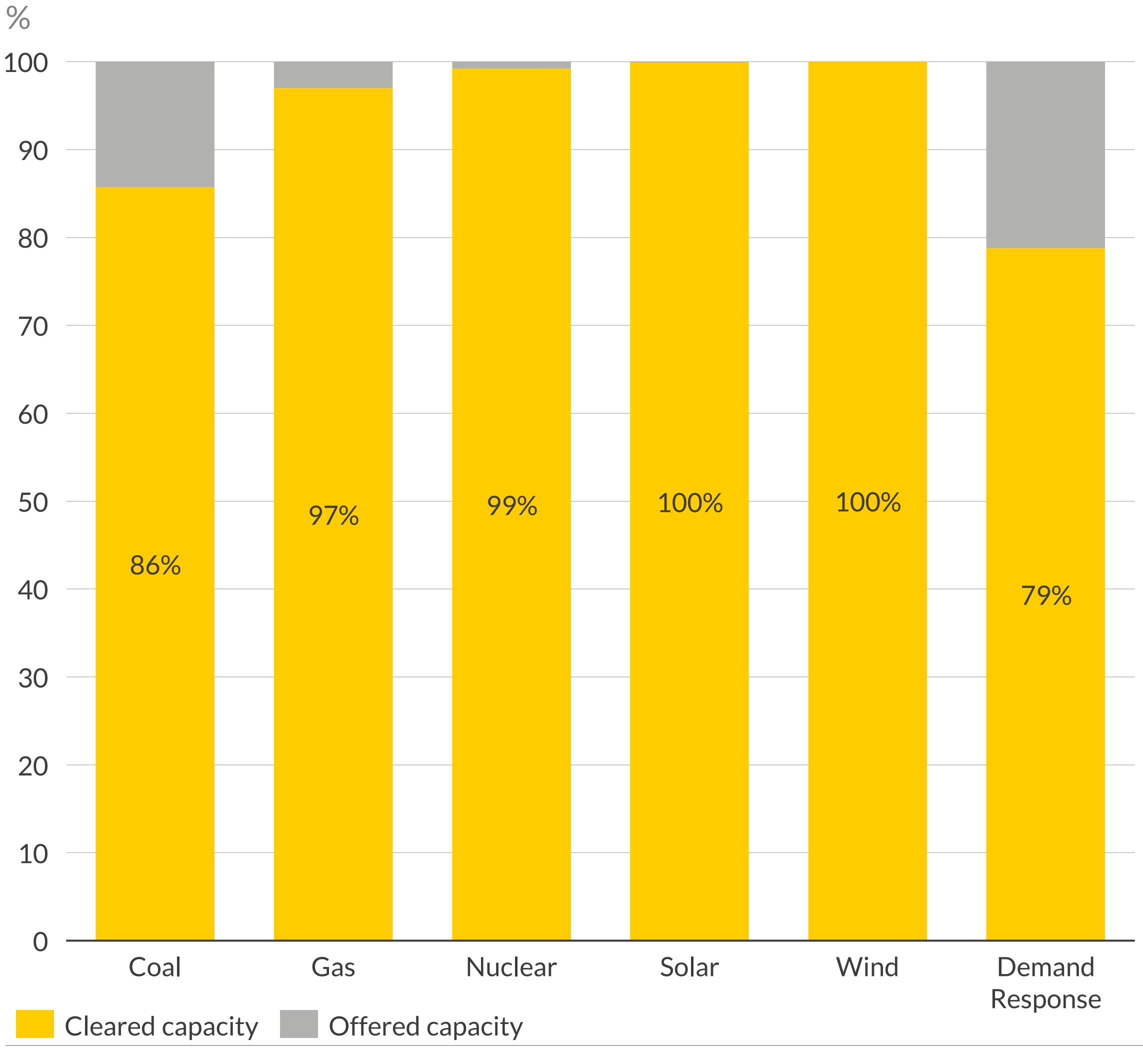
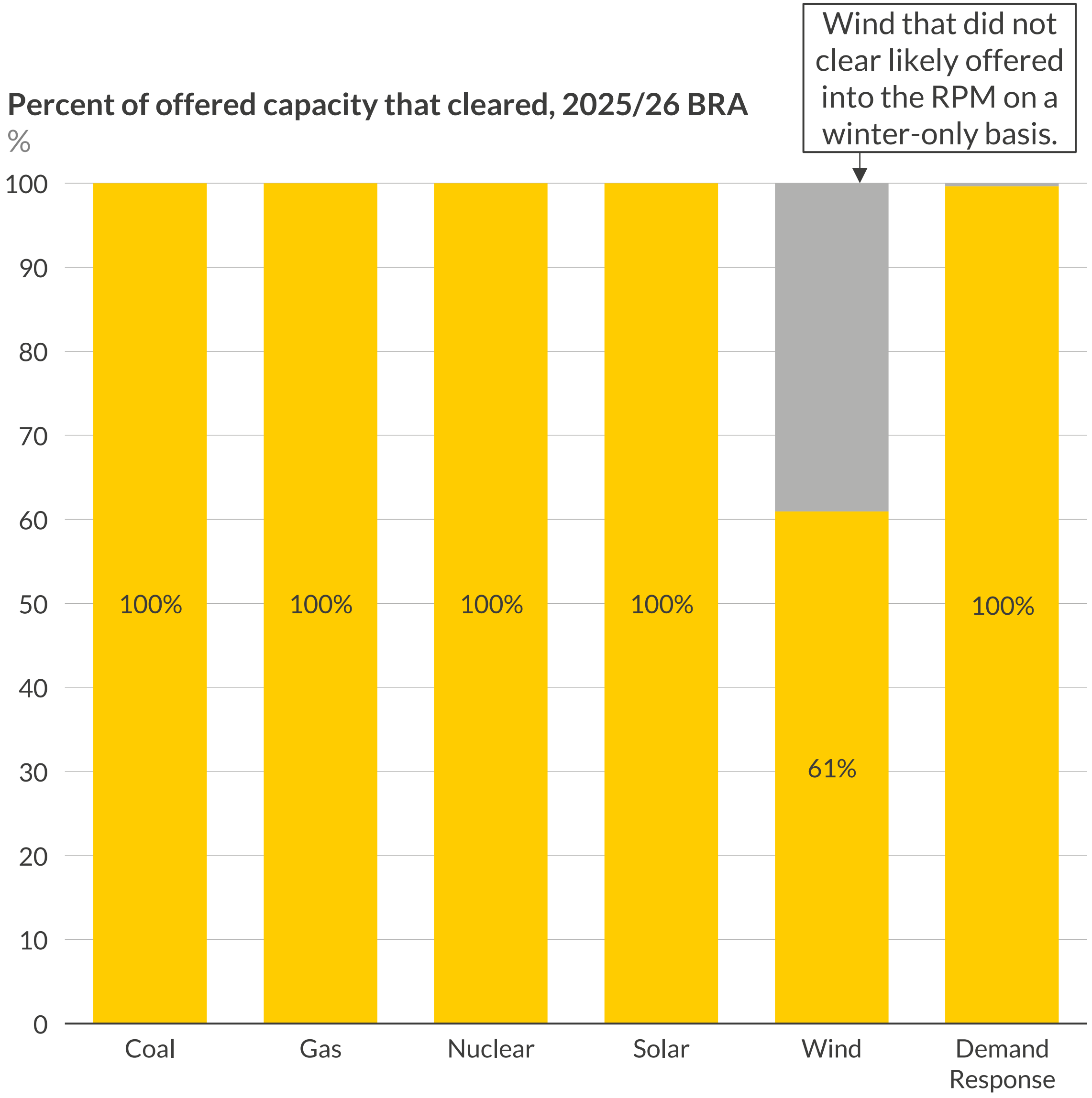
Percent of offered capacity that cleared, 2024/25 BRA



Percent of offered capacity that cleared, 2025/26 BRA



Sources: PJM, Aurora Energy Research

Supply | PJM reported 9.8GW ICAP as "excused" from the 25/26 BRA, comprising categorically exempt resources and retiring thermal plants

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Resources "excused" from 2025/26 BRA

	Total ICAP GW	Associated plants MW ICAP	Likelihood of re-entering capacity market
Reliability must run (RMR) plants	2.4	Brandon Shores (1,282); Wagner units 3-4 (702); Indian River (412)	**Very unlikely:** these plants have already confirmed retirement dates and secured revenue through retirement via the RMR agreements.
Other thermal deactivation requests	1.5	Eddystone (760); Sayreville (217); Vienna (167); Carlls Corner (75); Mickleton (57); Perryman 6 Unit 1 (55); Wagner units 1, CT 1 (139)	**Unlikely:** Withdrawn deactivation requests are precedented, but rare. Certain of these plants (Carlls Corner, Mickleton, and Sayreville) formally retired in June 2024.
Categorically exempt resources	~6	Not available, but the IMM reported that 3.9GW ICAP of intermittent resources and 1.3GW ICAP of storage resources elected not to offer into the 2024/25 BRA.	**Unclear; moderately likely that a portion will re-enter:** ▪ Information on why these resources did not participate is not publicly available, but avoiding of capacity performance penalties is likely a key factor. ▪ High clearing prices and a lack of CP penalties in much of the RTO for the 2026/27 delivery year (due to $0 net CONE) may incentivize capacity to return.

- **Methodology note:** PJM does not publish the data shown here explicitly, except for total excused capacity. The capacities and generators listed are the result of Aurora's analysis, based on the best available data.
- **Almost all resource classes are subject to capacity market must-offer requirement**, and PJM only grants exemptions under specific circumstances:
  - If the resource has submitted a deactivation request to PJM.
  - If the resource has "significant physical operational restrictions" or is "under major repair."
  - If the resource has committed to provide capacity to a region outside PJM.
- Intermittent, Demand Response, and storage (including hydroelectric pumped storage) resources are **categorically exempt** from the capacity market must-offer requirement.

Sources: Aurora Energy Research, PJM

Supply | Thermal plants that did not participate in the 2025/26 BRA due to planned retirements are concentrated in Eastern PJM, particularly BGE

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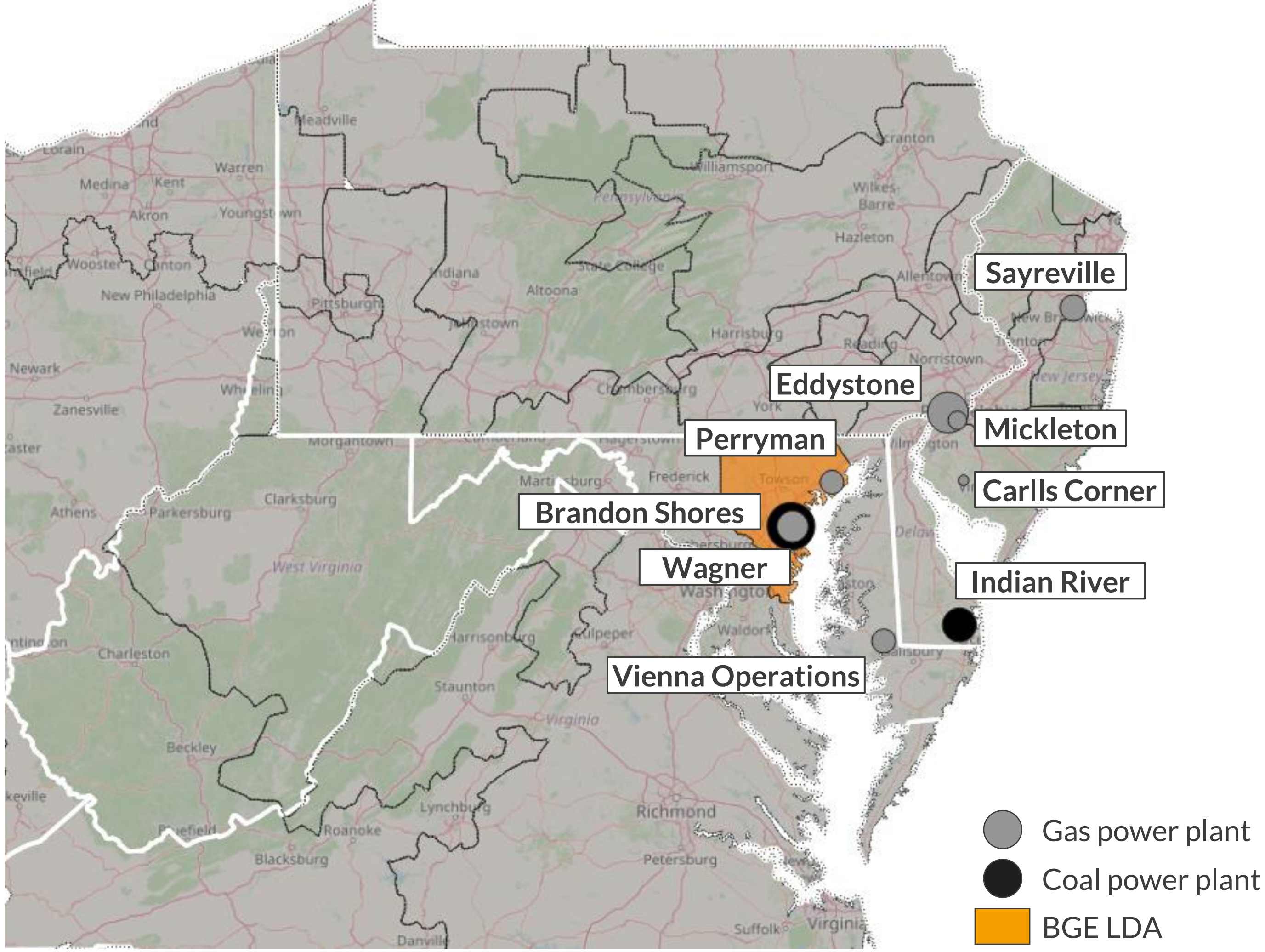
Resources "excused" from 2025/26 BRA due to planned deactivation



The retiring thermal plants that PJM excused from the 2025/26 BRA were concentrated in the eastern portion of PJM, particularly in the Baltimore Gas & Electric (BGE) LDA in Maryland.

- The 1.3GW ICAP Brandon Shores plant and 0.7GW ICAP Wagner plant, both of which are operating through 2028 on Reliability-Must-Run (RMR) contracts, did not participate in the 2025/26 BRA.
- The loss of these plants from the 2025/26 BRA left BGE with only 0.6GW UCAP of internal capacity, resulting in the BGE LDA clearing at its price cap of $444.26/MW-day.
- Prompted by concerns over the impact of capacity market prices on consumer energy bills, ratepayer advocates in several PJM states (including Maryland) have urged PJM to account for the RMR units in the capacity market, even if that requires delaying the 2026/27 BRA.

Methodology note: PJM does not publish the plants shown here explicitly, except for total excused capacity. The power plants listed are the result of Aurora's analysis, based on the best available data.

Demand | 2025/26 BRA demand rose sharply compared to previous auctions primarily due to PJM's 2024 peak load forecast increase

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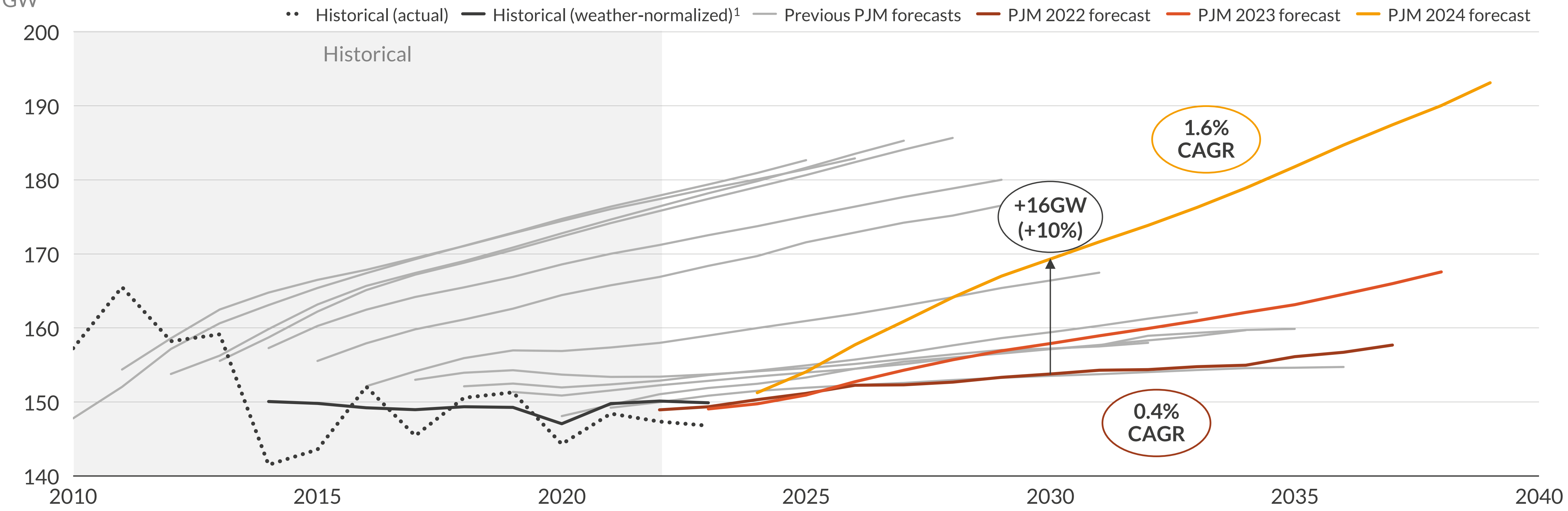
Historical and forecasted RTO coincident peak load
GW



- PJM has consistently overpredicted peak and total annual load, repeatedly shifting its forecast back year-on-year during the last decade.
- Despite PJM's expectations of load growth, peak load in PJM has generally decreased since 2010, primarily due to efficiency improvements.
- Between its 2022 and 2024 load forecasts, PJM raised its 2030 expectations for coincident peak load by 16GW (10%), primarily due to increased expectations of data center and EV growth.

1) As reported by PJM.

Sources: Aurora Energy Research, PJM

Agenda

I. 2025/26 BRA: results & drivers

II. CIFP capacity market reforms

III. 2026/27 BRA: parameters, drivers, & expectations

IV. Long-term forecast

CIFP reform | On Jan 30th, 2024, FERC approved one of PJM's CIFP capacity market reform filings, rejecting the other on Feb 6th

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On Jan 30, 2024, FERC conditionally accepted PJM's proposal to reform risk modeling and capacity accreditation within its capacity market, based on PJM's "CIFP"[1] fast-track process.

The 2025/26 BRA was the first auction held under PJM's CFP reform rules.

PJM CIFP capacity market reform timeline

Feb 2023 · Aug 2023 · Jan 2024 · Apr 2024 · Jul 2024

Feb 24: **PJM's board initiated the Critical Issue Fast Path ("CIFP")** stakeholder process to "address resource adequacy challenges" in the capacity market.

Aug 23: In final stakeholder vote on CIFP Capacity Market reform proposals, no proposal passed sector-weighted endorsement threshold. The non-binding vote left the final decision to PJM's board. Stakeholders' favored option would only reduce CP[3] penalties, with PJM's annual CIFP proposal coming in second.

Oct 13: **PJM submitted its "CIFP" capacity market reform proposals** to FERC,[2] significantly reducing capacity accreditation, imposing stricter reliability testing, and increasing MSOC[4] to include CPQR[5] costs.

Nov 17: FERC issued deficiency notices for PJM's CIFP capacity market reform filings.

Dec 1, Dec 8: PJM filed replies to FERC's deficiency notices, resetting FERC's 60-day window to issue a ruling.

Jan 30, Feb 6: **FERC conditionally approved PJM's filing ER24-99** (updating PJM's risk modeling & capacity accreditation), pending another compliance filing; **and rejected filing ER24-98** (to reform MSOC), citing insufficient detail and explanation.

Feb 16: PJM submitted FERC's requested compliance filing.

Feb 26: FERC granted PJM's request to delay the 2025/26 BRA[6] by 35 days, to Jul 17, along with associated pre-auction deadlines.

Apr 25: FERC accepted PJM's compliance filing, officially finalizing approval for PJM's reforms.

Jul 23: The auction window closed for the 2025/26 BRA—the first auction running under PJM's CIFP reform rules. PJM published results on **Jul 30**.

1) Critical Issue Fast Path 2) Federal Energy Regulatory Commission 3) Capacity Performance. 4) Market Seller Offer Cap, a bid cap in PJM's capacity market. 5) Capacity Performance Quantifiable Risk. 6) Base Residual Auction.

Sources: Aurora Energy Research, PJM

CIFP reform | The 25/26 BRA is the first to reflect PJM's updates to risk modeling and capacity accreditation through its CIFP process

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PJM's filed capacity market reforms following its CIFP stakeholder process

	Docket No. ER24-98 Rejected by FERC (but PJM may still refile)	Docket No. ER24-99 Implemented in 2025/26 BRA	Expected BRA Impact: Resource accred.	Amount procured	Bids	Clear. Price
Capacity Accreditation		▪ Move all resources (incl. demand) to **marginal ELCC**[1] ▪ Include separate **"dual-fuel" class categories** for natural gas resources	↓	↓/↑[2]	↑	↑
Risk modelling		▪ Adopt **Expected Unserved Energy (EUE) as key metric** (replacing current LOLE[3]) ▪ Model risk on hourly level with more weather years				
Market Seller Offer Cap (MSOC)	▪ **Include Capacity Performance Quantifiable Risk (CPQR) cost in MSOC** (PJM's bid cap) ▪ Clarify CPQR definition		-	(↓)	↑	↑
Capacity Performance	▪ Performance payments only for cleared resources ▪ Exclude resources excused from non-performance charges from Balancing Ratio calculation	▪ **Reduce penalty cap** ("stop-loss limit") ▪ Capacity testing required in summer & winter ▪ Add generation operational testing	-	-	↓/↑	↓/↑
E&AS offset	▪ **Forward-looking Energy & Ancillary Services (E&AS) offset** for MSOC, MOPR		-	-	-	-
FRR[4] alignment	▪ Apply Capacity Performance incentive revisions to FRR rules	▪ Align FRR rules with capacity market, e.g. capacity shortfall charges	-	-	-	-
Participation rules		▪ Require **binding notice of participation intent** from planned generation resources ▪ Revisions to sell offer requirements	-	-	-	-

1) Effective Load Carrying Capacity (ELCC) is a measure of a resource's contribution to reliability. 2) Reduced ELCCs indirectly increase procurement targets. However, PJM modeling determines that under stricter ELCC derating, less UCAP is required to meet reliability targets. 3) Loss of load expected. 4) The Fixed Resource Requirement (FRR) alternative is an option for load-serving entities to meet resource adequacy requirements outside the capacity market, e.g. via internal resource planning.

Sources: Aurora Energy Research, PJM

CIFP reform | Lower capacity accreditation is driven by a shift of all asset types to marginal ELCCs[1] and a focus on winter risk

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Drivers of the CIFP reforms' decrease in capacity accreditation

	Driver	Impact
Thermal to ELCC[1]	**All resource types moved to using ELCC for conversion to UCAP[2].** ▪ Thermal resources previously used "EFORd[3]" metric, defined by historical probability of a forced outage, uncorrelated to system risk. ELCC does capture such risk correlation and is thus typically lower. ▪ Renewable, intermittent, and duration-limited (e.g. storage) resources already used ELCC.	**Higher thermal bids, raising clearing prices because thermal usually price-setting.** ▪ As bids are per MW UCAP, assets must raise bids when capacity accreditation falls, to keep their effective bid per MW nameplate constant.
Marginal ELCC	**Move from "average ELCCs" to "marginal ELCCs", which are typically lower.** ▪ Average ELCCs measure the average contribution of any MW within a class to system reliability. ▪ Marginal ELCCs measure the contribution of an additional MW to reliability, which is typically below the average due to correlated outage risks and cannibalization within a technology type.	**Renewables, batteries, and natural gas ELCCs most affected.** ▪ These technologies have stronger correlations (between assets of same type) in their ability to reduce system risk than some others (coal, nuclear). E.g. solar assets typically generate at roughly the same time; natural gas outages are often caused by regional fuel deliverability issues. The technologies' ability to contribute to system reliability thus saturates as more MW are built, lowering marginal ELCCs.
Winter risk	**Shift in focus from primarily summer risk to primarily winter risk, resulting from updated risk modelling methodology.** ▪ Capacity market previously focused on summer risk, when peak load occurs. ▪ A key driver in this shift has been the move to Expected Unserved Energy ("EUE", in MWh) as the metric for outages, rather than Loss of Load Expected ("LOLE", in event-days per year). ▪ PJM has also increased the granularity of its risk modelling and extended it to more historical years.	**Lower ELCCs for assets with lower reliability contribution during winter risk, and vice versa for assets with higher winter reliability.** ▪ Solar and battery reliability contributions lower, because winter system stress events are generally longer than summer events. ▪ Gas ELCCs lower due to risk of weather-driven mechanical failure and correlation between winter storms and natural gas deliverability issues. ▪ Wind ELCCs higher, as wind typically generates more in winter.

1) Effective Load Carrying Capability. 2) Unforced Capacity—i.e., capacity after accreditation adjustment. PJM's capacity market uses MW UCAP as its native unit for capacity. 3) Equivalent Demand Forced Outage Rate.

Sources: Aurora Energy Research, PJM

CIFP reform | Capacity accreditation decreased for most technologies in the 2025/26 BRA, with solar, batteries, gas, and DR most affected

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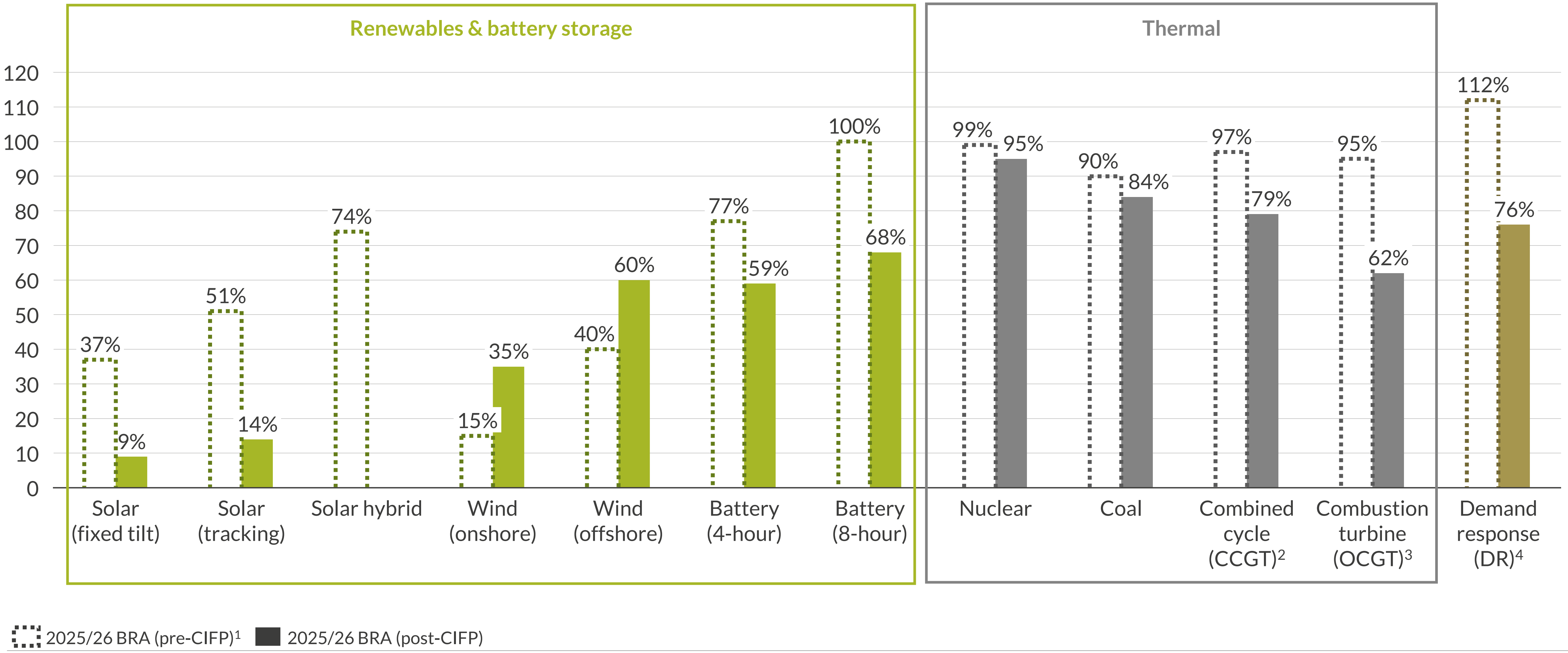
ELCC values by technology for the 2025/26 BRA[1]

%



1)"Pre-CIFP" values for thermal plants reflect historical average of [1 - EFORd] per technology class. 2) Combined cycle gas turbine. 3) Open cycle gas turbine.
4) Before CIFP, Demand Response resources were effectively awarded a value equal to the Forecast Pool Requirement (FPR), which PJM recommended be set at 1.1171 for the 2025/26 delivery year in its October 2023 Reserve Requirement Study.

Sources: Aurora Energy Research, PJM

Revenues | Solar PV and onshore wind see opposite ELCC impacts from CIFP reform, but capacity revenues increase for both due to a high clearing price

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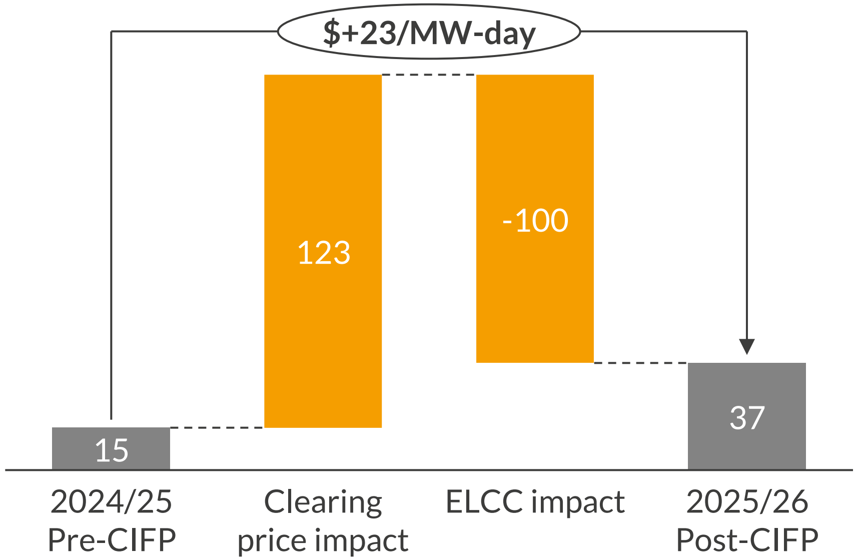
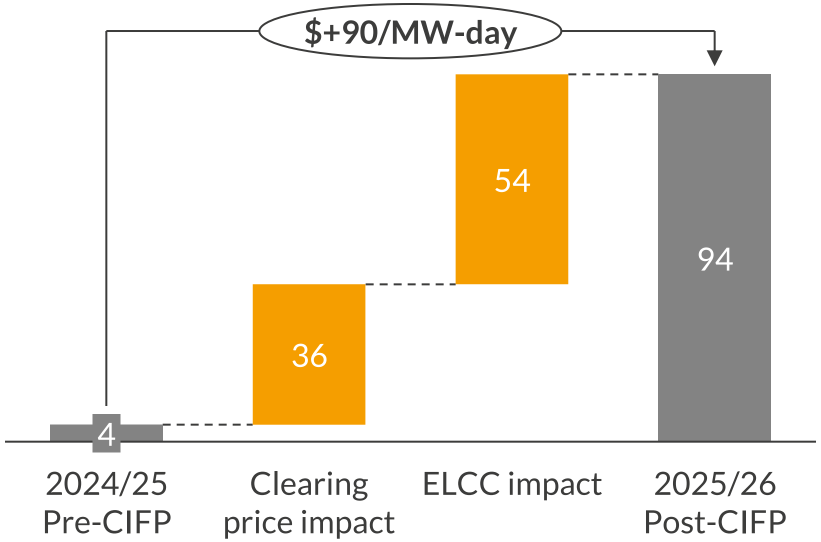
Capacity revenue change from 2024/25 to 2025/26 BRA (RTO-level clearing price)
$/MW-day

Solar PV (single-axis tracking)



- Capacity revenues for tracking solar PV see a $23/MW-day increase between the 2024/25 and 2025/26 BRAs due to a rise in clearing price.
- The impact of the large reduction in tracking solar's ELCCs —down from 51% pre-CIFP to just 14% post-CIFP—is mitigated by the $123/MW-day impact due to the change in clearing price.

Onshore wind



- Post CIFP reform, onshore wind capacity revenues increased by ~$90/MW-day, with the increased ELCC values—15% to 35%—contributing $54/MW-day. Onshore wind ELCCs were adjusted in May 2023 after PJM's ELCC methodology update capping modeled output at CIR.
- Wind's higher ELCCs are due to PJM's risk modeling improvements shifting significant perceived reliability risk to winter months, when wind output is generally higher and more stable.

Total   Impact

Source: Aurora Energy Research

Revenues | Natural gas assets can expect an overall increase in capacity revenues, despite lower ELCCs

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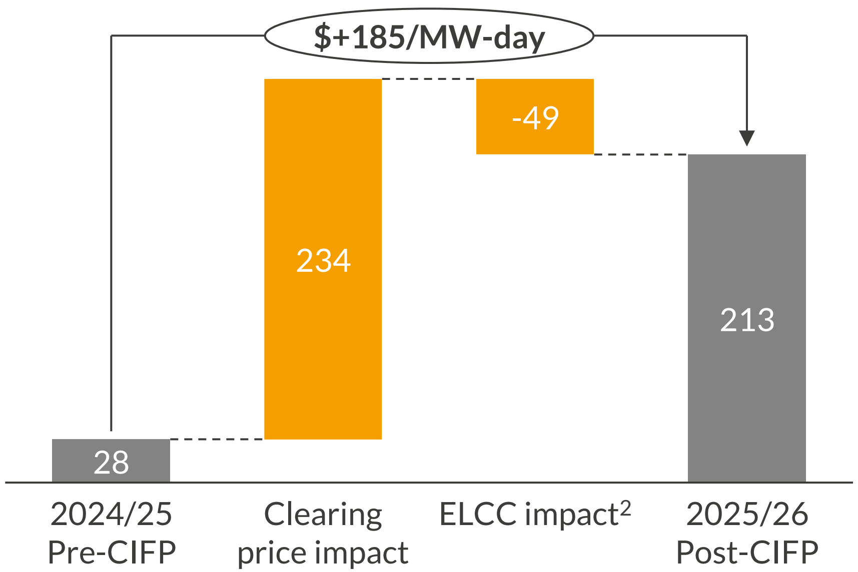
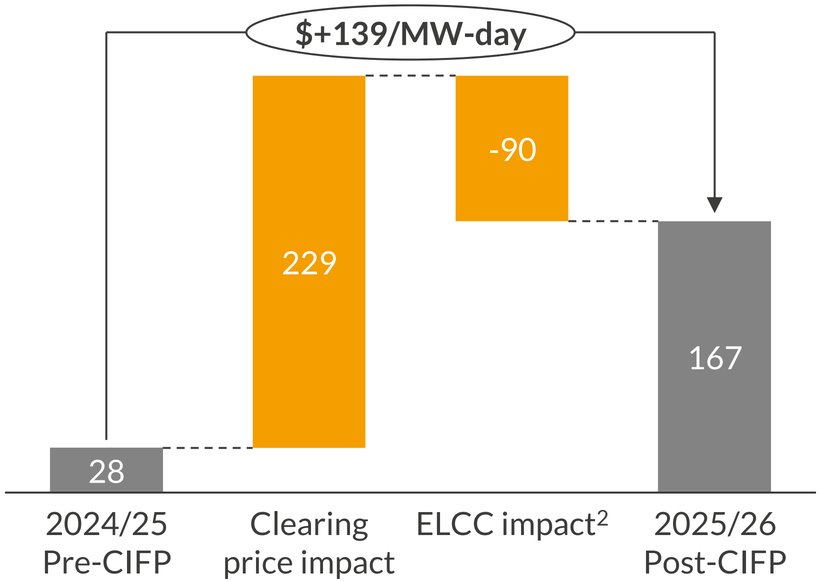
Capacity revenue change from 2024/25 to 2025/26 BRA (RTO-level clearing price)
$/MW-day

Natural gas CC (CCGT)



- Capacity revenues for a CCGT in PJM could rise by $185/MW-day due to clearing price impact, despite its capacity accreditation falling from 97% to 79%.[1]
- $234/MW-day impact due to the price mitigates all the $49/MW-day downside from the accreditation decrease.

Natural gas CT (OCGT)



- Combustion turbines take a stronger hit to capacity accreditation due to CIFP—falling from 95% to 62%[1]—which results in a higher decrease in capacity revenues of $90/MW-day.
- However, this decrease is once again mitigated by the $229/MW-day impact of the rising clearing price.

Total Impact

1) Based on Aurora estimate of "status quo" EFORd values and CIFP ELCC values published by PJM.

Source: Aurora Energy Research

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Timeline | The 2026/27 BRA will take place 18 months before the delivery year, with a return to 36 months planned for the 2029/30 BRA

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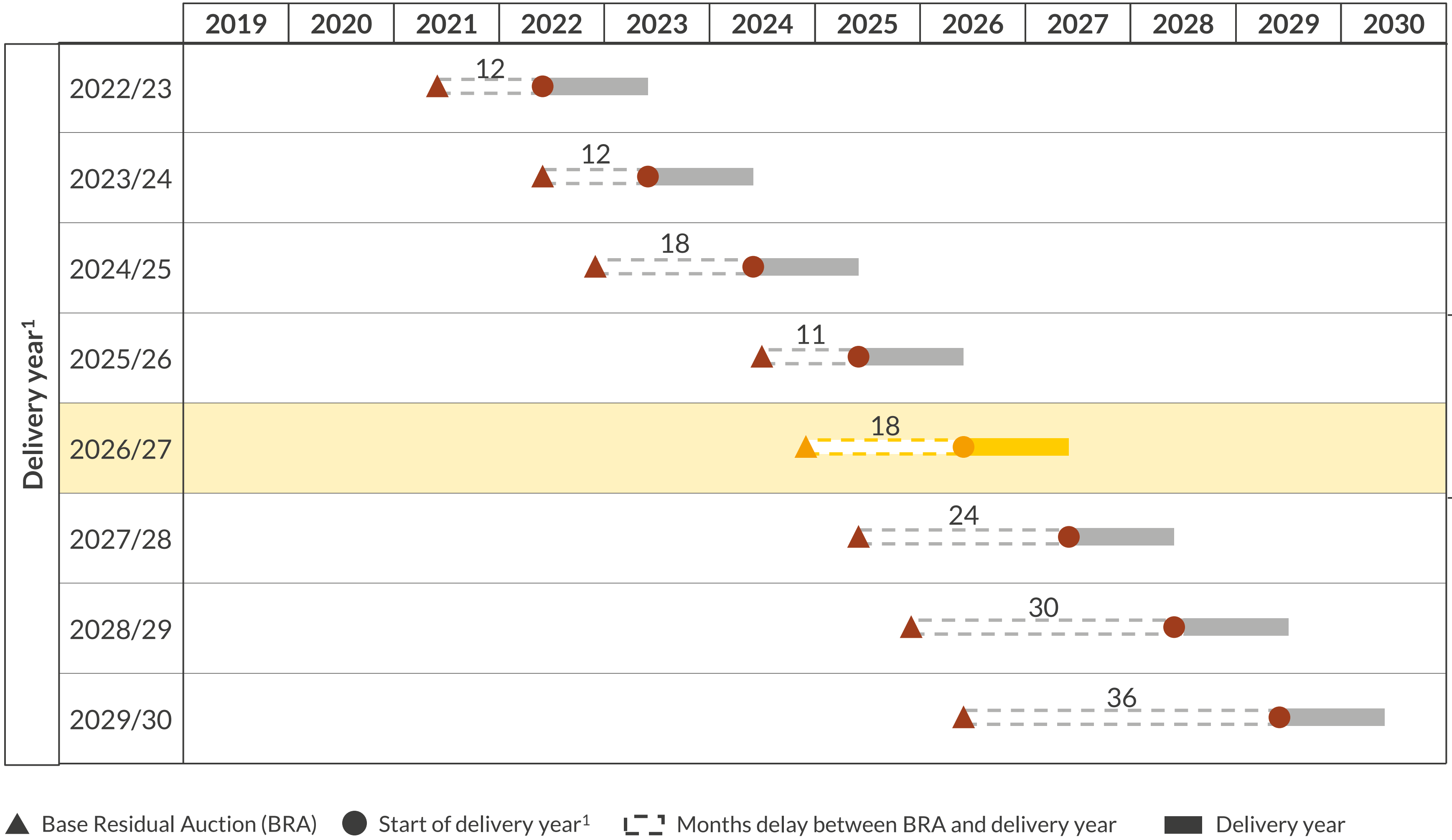
PJM's Base Residual Auction (BRA) schedule



The BRA schedule—typically 36 months ahead of each delivery year—was significantly delayed for the 2022/23 delivery year, due to several FERC rulings and related stakeholder management and counterproposals by PJM, most importantly concerning changes to PJM's Minimum Offer Price Rule (MOPR)

PJM also delayed the 2025/26 BRA, due to its CIFP capacity market reforms and changes to the capacity performance construct, reducing the auction lead time to 11 months.

PJM has published a schedule for incrementally increasing the time between BRA and delivery year starts, returning to their original schedule by the 2029/30 BRA, with 2028/29 BRA having a shorter 30-month lead time.

1) Delivery years run from June 1 through May 31.

Sources: Aurora Energy Research, PJM

Drivers | Demand has risen by 3GW compared to the previous BRA, while changes in supply are highly uncertain—with >3GW additions feasible

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	Factor	Key changes from 25/26 BRA, GW UCAP	Price impact	Explanation
Supply	New entrants	+ 0.8-5.5	↓	▪ Trumbull CC (0.8GW UCAP) expected to participate for first time. ▪ Additional capacity possible due to new batteries, renewables, DR, and imports; incentivized by high expected clearing prices and low capacity performance penalties (due to the $0 Net CONE in many regions, yielding a $0 penalty rate).
	Re-entry of exempt resources	+ 0-2.0	↓	▪ Up to ~6GW ICAP available that withheld from 2025/26 BRA. ▪ Incentivized by abovementioned high clearing prices and low capacity performance penalties, but unclear how much will re-enter, if any.
	ELCC changes	- 1.2	↑	▪ Lower ELCCs for renewables and batteries will reduce effective supply (partially offset by higher ELCCs for combustion turbines).
	Retirements	- 0-1.5	↑	▪ New retirements possible despite expected high capacity prices, e.g. due to environmental regulations.
Demand	Reliability requirement	RTO: +2.8 DOM: +0.9	RTO: ↑ DOM: ↑	▪ Strong increase in forecasted RTO-wide and Dominion peak load driven primarily by data center additions, raising reliability requirements.
	VRR curve shape	*Significantly steeper*	↑/↓	▪ Caused by updated VRR parameters and a switch to a gas CC as PJM's reference generator, significantly raising Gross CONE (which sets the VRR's upper bound) and lowering Net CONE (to $0/MW-day for much of the RTO).
LDAs	CETL	EMAAC: -1.1 SWMAAC: -1.2 DOM: +1.5	EMAAC: ↑ SWMAAC: ↑ DOM: ↓	▪ Significantly lower CETL in EMAAC and SWMAAC may constrain capacity imports, potentially causing price separation in these LDAs. ▪ Dominion's CETL increase more than offsets its higher reliability requirement, potentially lowering its clearing price compared to the 2025/26 BRA.

Sources: Aurora Energy Research, PJM

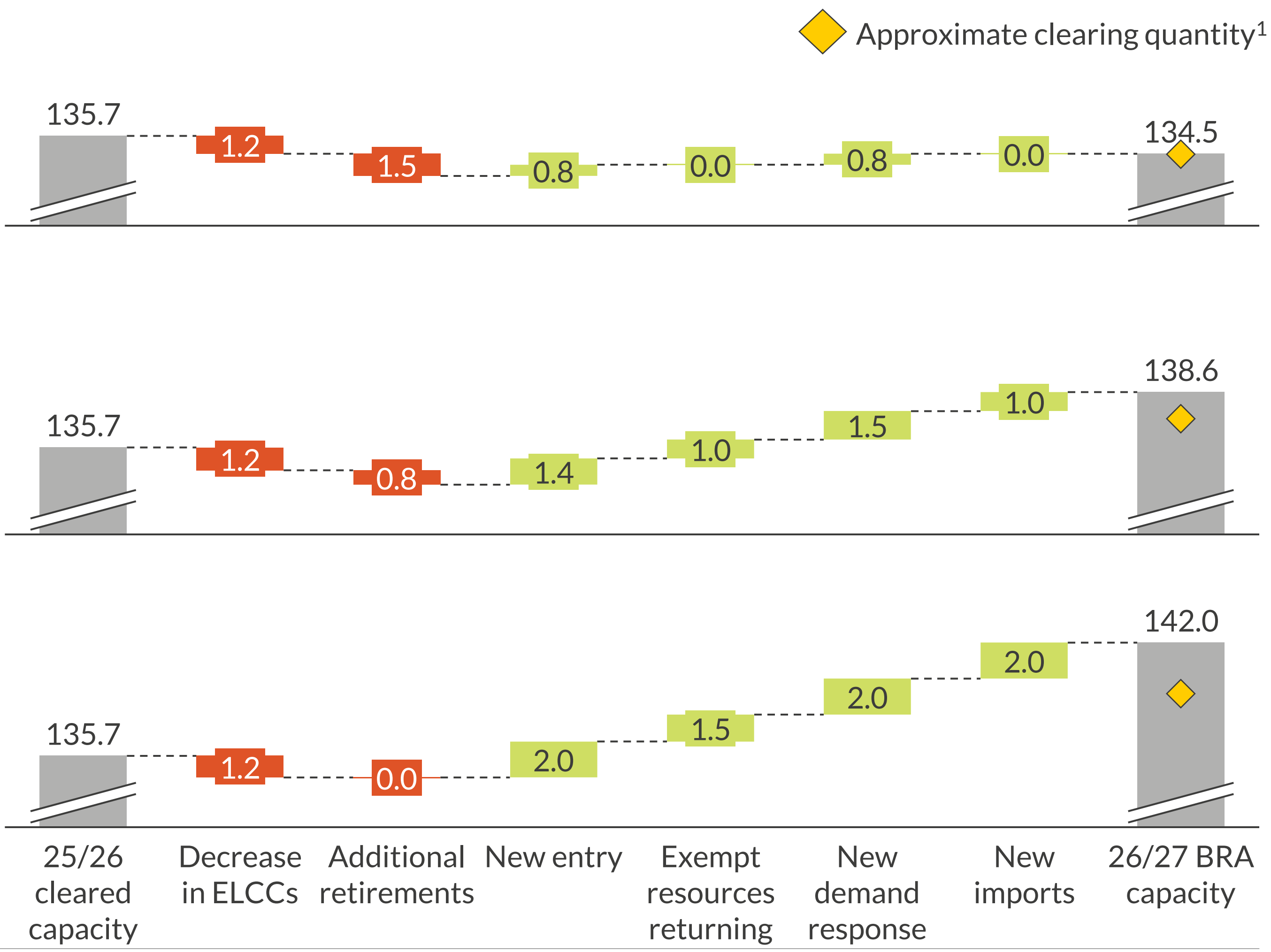
Supply | 2026/27 BRA prices could range from $100 to $700/MW-day, depending on supply—with a $200-$300 Central expectation

Sources of capacity supply shifts for 2026/2027 BRA, GW UCAP

High case
- Clearing price: **$696/MW-day**
- Price setter: RPM price limit

Central case
- Clearing price: **$200-300/MW-day**
- Price setter: New unit or higher-cost DR[2]

Low case
- Clearing price: **~$100/MW-day**
- Price setter: Existing unit or lower-cost DR



- The amount of supply anticipated to participate in the 2026/27 BRA ranges from 134.5 to 142.0GW UCAP.
  - Supply decreases, relative to the 2025/26 BRA, range from 1.2GW UCAP to 2.7GW UCAP, depending on additional retirements.
  - Supply increases range from 1.6GW to 7.5GW UCAP, depending on new entry, exempt resources re-entering the capacity market, and incremental demand response and import participation.
- Small changes in supply could drive large differences in clearing prices—the "Low supply" case would result in clearing at the price cap, while the "High supply" case would likely see a clearing price set by an existing unit or lower-cost demand response resource.

1) 2026/27 BRA capacity reflects total capacity offering into the auction. The quantity of cleared capacity depends on the amount of offered capacity, bid levels, and the shape of the VRR curve. 2) Demand response.

Sources: Aurora Energy Research, PJM

Supply | 2026/27 ELCCs increased by 6p.p. for combustion turbines but decreased slightly for most renewables and batteries, relative to 2025/26

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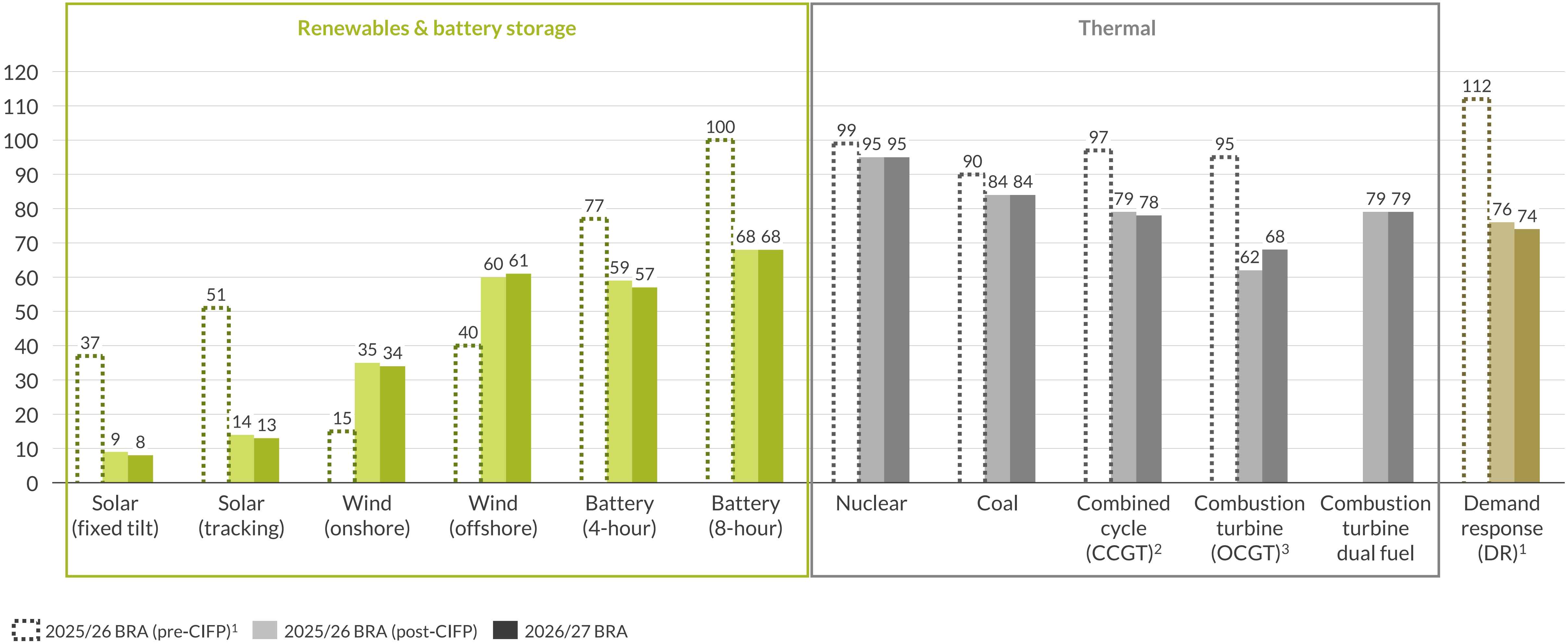
Capacity accreditation by technology[1]
%



1)"Pre-CIFP" values for thermal plants reflect historical average of [1 - EFORd] per technology class; for DR, "pre-CIFP" values are effective, as implied by PJM's parameters through the 2025/26 BRA's FPR. All other values are ELCCs. 2) Combined cycle gas turbine. 3) Open cycle gas turbine.
Sources: Aurora Energy Research, PJM

Supply | Much of PJM has $0 Net CONE for 2026/27, removing Capacity Performance penalty risk and potentially incentivizing more supply

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Many areas of PJM will have effectively no capacity performance penalty for the 2026/27 delivery year, due to their Net CONE[1] dropping to $0/MW-day.

- **This could incentivize additional supply to (re-)enter the capacity market that previously may have withheld due to penalty risk**—e.g. renewables, which are exempt from must-offer obligations and susceptible to penalty risk, having little control over output during system stress events.
- Because the capacity performance penalty rate for each 5-minute interval is proportional to Net CONE, performance penalties are null when Net CONE falls to $0:

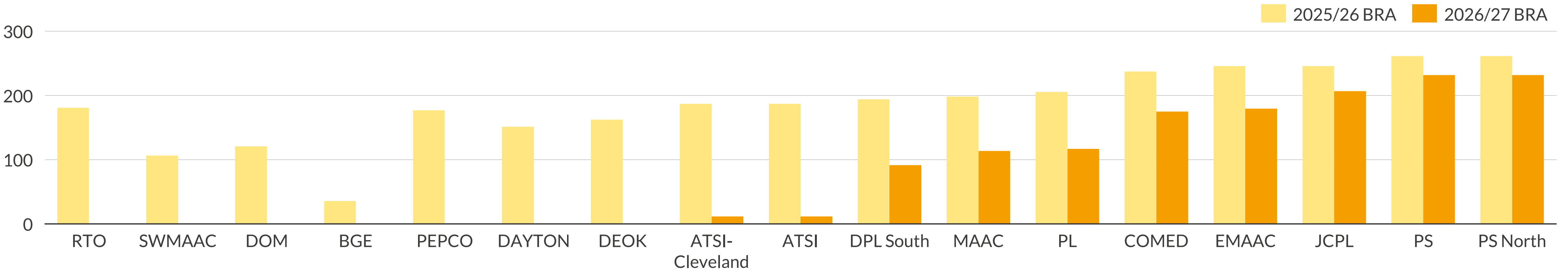
$$Charge\ Rate_{LDA} = \frac{Net\ CONE\ (ICAP)\ _{LDA}}{360}$$

Risks:

- Even with a $0 Net CONE, capacity generators will be subject to capability testing and penalties for test failure. Intermittent resources are exempt from such tests, however.
- This may increase penalty risk for LDAs with a non-zero Net CONE, as (i) much of the RTO has little incentive to perform, potentially triggering drawn-out PAIs[2] and (ii) the total penalty cap is proportional to the BRA clearing price, which could be as high as $700/MW-day.
- Although it has not stated any plans to do so, PJM could reform its capacity performance penalties to ensure a non-zero penalty rate.

Net CONE for PJM RTO and LDAs

$/MW-day ICAP



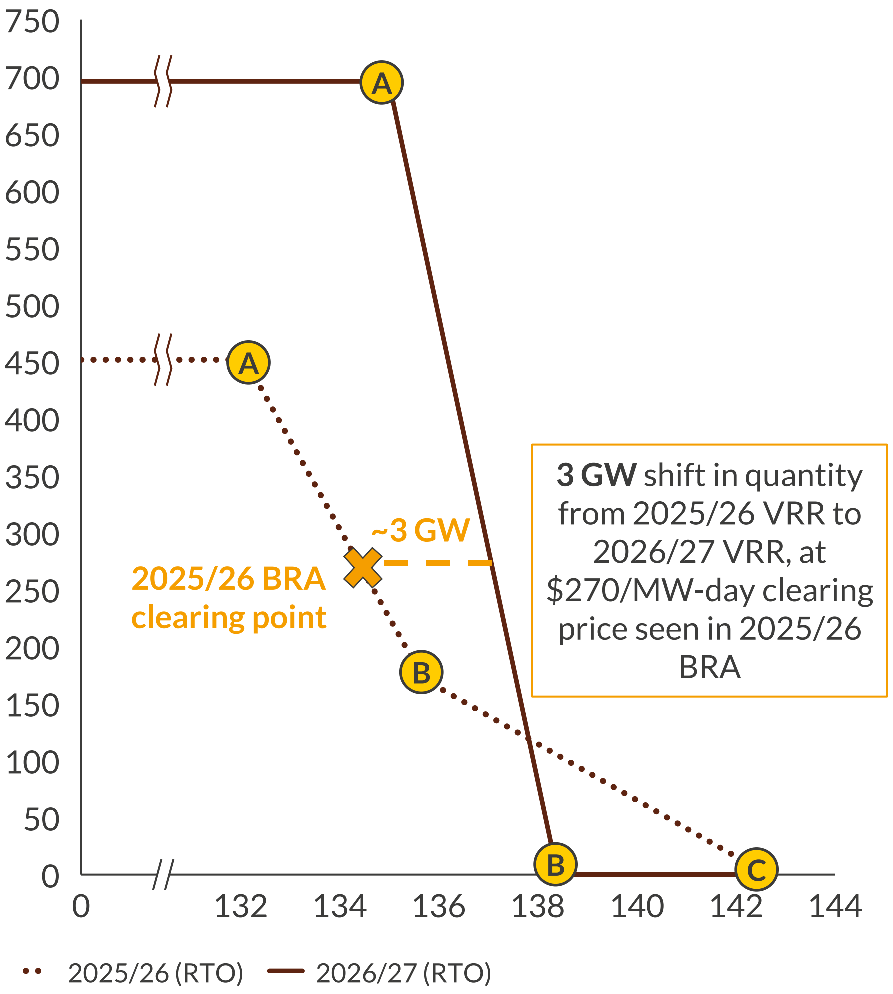
1) Net cost of new entry—an annualized estimate of the revenue required to cover fixed and capital costs, net of margins earned from energy and ancillary services. 2) Performance Assessment Intervals.

Sources: Aurora Energy Research, PJM

Demand | The 2026/27 BRA's VRR curve is much steeper than previously, making price outcomes significantly more volatile

AURORA

RTO-wide VRR curve[1], incl. point definitions
$/MW-day (nominal), GW UCAP



Key impacts of VRR curve changes

1. The steeper shape of the 2026/27 VRR curve—resulting from changes to the parameters underlying the VRR—increases clearing price uncertainty and volatility.
2. The outward shift of the 2026/27 VRR curve—resulting from increases to PJM's Reliability Requirement—implies that at least 3GW of additional supply is necessary to maintain a clearing price at or below the $270/MW-day seen in the 2025/26 BRA.

Key parameter changes for the 2025/26 BRA relative to the previous auction

Parameter	2025/26 BRA (prev. auction)	2026/27 BRA (next auction)	Driver(s)
Reliability Requirement	144,450MW	147,246MW	▪ Increase in forecasted RTO peak load of 3.3GW
Gross CONE (determines point A)	$451.6/MW-day UCAP	$695.8/MW-day UCAP	▪ Shift in the VRR reference resource from a combustion turbine to a combined cycle, which is both more capital intensive (increasing Gross CONE) and more lucrative in energy and ancillary services markets (decreasing Net CONE).
Net CONE (determines point B)	$228.8/MW-day UCAP	$0/MW-day UCAP	

1) Variable Resource Requirement—PJM's capacity demand curve, defined by 3 points. 2) VRR curves are net of FRR demand. As PJM has not yet released FRR designations for the 2026/27 BRA, the values here assume identical FRR participation from the 2025/26 BRA.
Sources: Aurora Energy Research, PJM

LDAs | SWMAAC, JCPL, DPL South, BGE, & EMAAC all have higher likelihood of price separation, due to tighter CETO:CETL ratios

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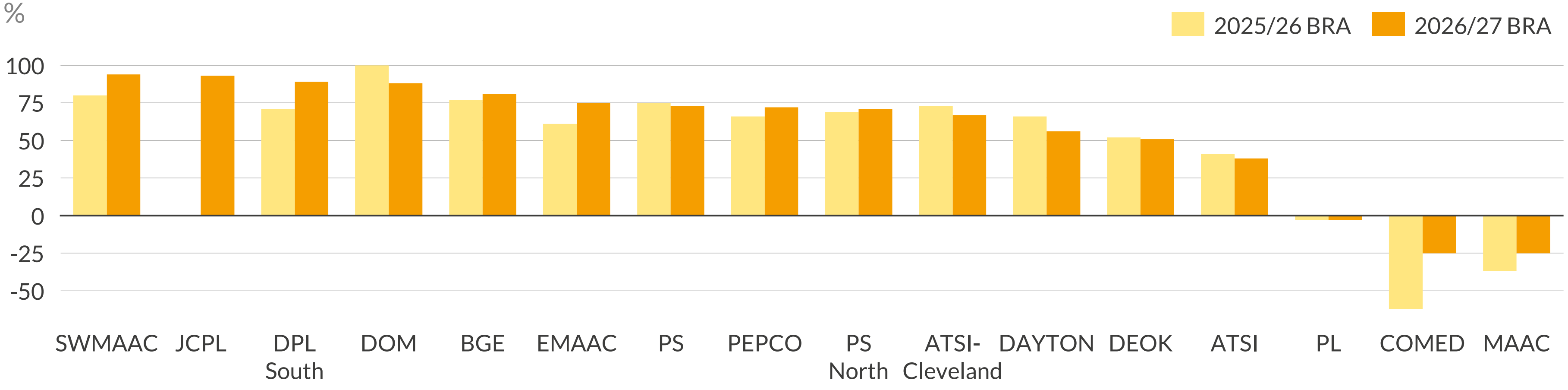
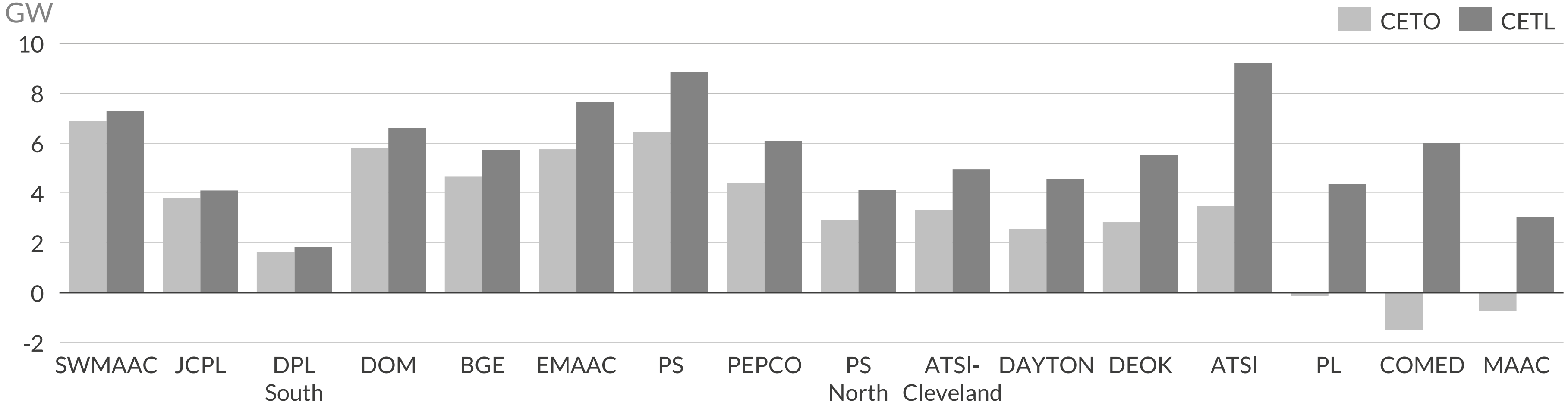
CETO:CETL ratio by LDA
%



*← **Higher ratio:** more likely to clear above parent region*

__Lower ratio:__ less likely to clear above parent region →

CETO and CETL by LDA (2026/27 BRA)
GW



Sources: Aurora Energy Research, PJM

- **Capacity Emergency Transfer Limits** (CETLs) determine how much capacity can be imported into an LDA during peak system stress moments, thus acting as constraints on PJM's cost optimization of the BRA.
- An LDA's **Capacity Emergency Transfer Objective** (CETO) is PJM's estimate of the capacity import necessary to satisfy loss of load expectation requirements.
- The closer CETO is to CETL, generally the more likely that LDA will clear above its parent price ("price separation").
- SWMAAC, JCPL, DPL South, Dominion, BGE, and EMAAC all have a relatively high likelihood of price separation, due to tight CETO:CETL ratios (≥75%).
- Of the above LDAs, only Dominion's CETO:CETL ratio is lower than the previous BRA.

LDAs | Dominion's large CETL increase could bring its clearing price as low as $198/MW-day, although $695 is still feasible

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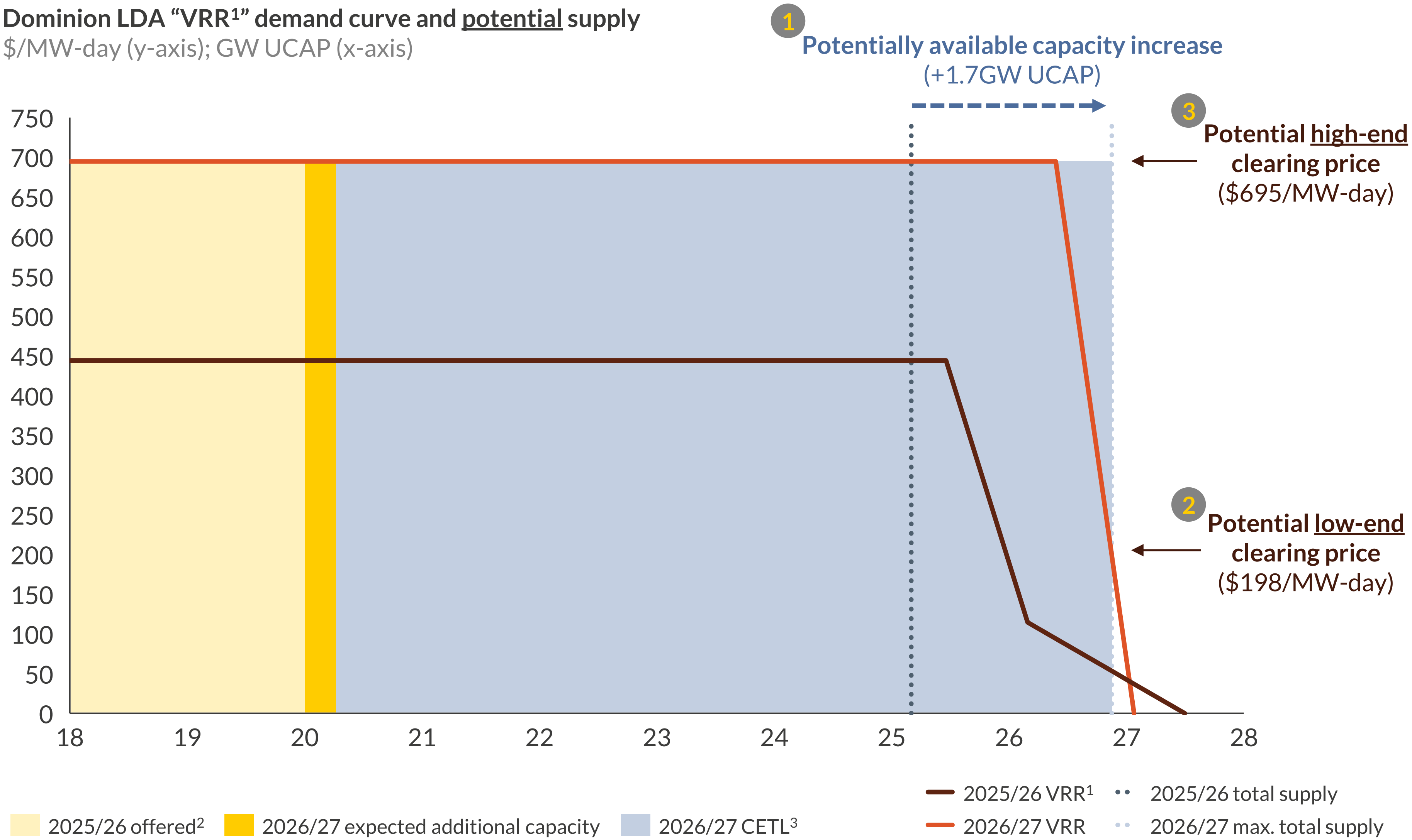
Dominion LDA "VRR[1]" demand curve and potential supply
$/MW-day (y-axis); GW UCAP (x-axis)



1. The total available capacity in Dominion—as indicated by PJM's auction parameters—has risen by 1.7GW compared the last auction, primarily due to its 1.4GW CETL[3] increase.
   - PJM expects net additional 0.3GW UCAP of capacity bidding within the LDA.
2. As a result, Dominion's price could clear as low as $198/MW-day, if the entire extent of the LDA's CETL is utilized and no participants bid above that level.[4]
3. However, neither of the abovementioned criteria are guaranteed—as underscored by CETO[3]<CETL, i.e. PJM's expectation that not all of CETL will be used—and Dominion could still feasibly clear at its auction cap of $695/MW-day if supply falls ≥0.5GW short of the 26.9GW available.

1) Variable Resource Requirement. 2) Excl. (estimated) capacity offered as winter-only but not cleared because no summer-only counterpart available. 3) Capacity Emergency Transfer Limit/ Objective. 4) Estimated from BRA parameters via [reliability requirement] - [CETO]. 4) Also assuming RTO does not clear >$198/MW-day; but in that case CETL would likely not be fully utilized.
Sources: Aurora Energy Research, PJM

Agenda

I. 2025/26 BRA: results & drivers

II. CIFP capacity market reforms

III. 2026/27 BRA: parameters, drivers, & expectations

IV. Long-term forecast

Outlook | Aurora's Central case expects clearing prices at $XX/MW-day levels

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5-year rolling average clearing prices for PJM's Base Residual Auction (BRA)
$/MW-day (real 2023)

Redacted

2026-2030

Prices around the $XX/MW-day level, as tight supply-demand conditions are expected to persist:

- PJM forecasts continued short-term peak load growth.
- Additional thermal resources (particularly coal plants) have announced retirements before 2030.

2031-2050

Sustained prices of $XX/MW-day, as newbuild is required almost every year:

- Retirements from gas plants built in the ~20s reaching end of life, new capacity needed.
- Gas capacity factors driven down by continued renewables growth and flexible demand (e.g., EVs); higher CM revenue needed.

Sources: Aurora Energy Research, PJM

Drivers | Peak load growth and retirements will persist until at least 2030, partially offset by potential new build, DR, and imports

Drivers of capacity price developments through 2029

	Factor	Expected change from 25/26 to 29/30 BRA GW UCAP	Price impact	Explanation
Supply	**New entrants**	+11	↓	▪ New resources primarily comprise solar, wind, and battery storage resources in the interconnection queue, with a small amount of additional thermal capacity possible.
	Other new sources of capacity	Imports: +4 Demand response: +4	↓	▪ The 2025/26 BRA saw low demand response and capacity import participation by historical standards. Higher RPM clearing prices will likely incentivize further participation from these resources.
	Retirements	-10	↑	▪ Coal plants totaling 7GW UCAP have announced retirements by 2029.[1] Some additional peaking capacity may also retire; though higher RPM clearing prices will incentivize these units to remain online.
Demand	**Peak load**	+12	↑	▪ PJM's 2024 load forecast sees peak load rising from **153.5GW** in 2025 to **165.7GW** in 2029. Because PJM uses its own forecasting to assess peak load for the RPM, this forecast provides a basis for near-term auctions.
	VRR curve shape	*Uncertain*	↑/↓	▪ PJM refreshes the parameters underlying the VRR curve annually. An increase in the Net CONE parameter above the $0/MW-day used for the 2026/27 BRA would result in a less steep VRR curve.

1) Rockport, Kincaid, Miami Fort, Keystone, Conemaugh.

Sources: Aurora Energy Research, PJM

Risks | Structural changes to PJM's capacity market or state policy could lower the price outlook, but most have low probability of occurring

Potential measures PJM or its member states may take that could reduce capacity market prices

Measure	Relevant areas	Estimated likelihood	Explanation
Interconnection queue fast-track process	PJM		▪ PJM is considering implementing a process that would allow "shovel-ready projects" to fast-track their interconnection and construction process, to benefit system reliability.[1] ▪ PJM's planning committee is also considering ways for new projects to bypass the interconnection queue by taking over retiring resources' capacity interconnection rights and physical locations.
Policy hindering impact of data centers on power grid	OH, VA		▪ Legislators in both OH and VA proposed multiple bills in 2023 and 2024 to regulate data centers' impacts on power costs, environment, and local land use. If successful, such bills could slow data center additions or oblige operators to source and pay for power in ways that minimizes impacts on PJM rates.
State subsidies for new generation	MD, PA		▪ State Delegates of MD—the state containing BGE, which cleared at $466/MW-day in the 2025/26 BRA—have announced potential plans to introduce bills to (i) add energy storage to the state's distribution grid and (ii) provide additional REC support to advanced-stage solar projects. ▪ PA Sen. Gene Yaw (R) has announced plans to introduce bills to (i) create a fund to support power plant construction (akin to the Texas Energy Fund) and (ii) increase certainty within the state's permitting process.
Include RMR plants in capacity auction	DE, DC, IL, MD, NJ, OH		▪ Ratepayer advocates from 6 states urged PJM in an August 30 open letter to include RMR units in the capacity auction. ▪ However, PJM uses RMR primarily to guarantee transmission security (rather than resource adequacy), and their inclusion in the capacity auction could distort the necessary price signals to replace the retiring plants.
State or LSE exit as FRR region to lower costs	-		▪ Although no states or utilities have announced intentions to opt out of PJM's capacity market, multiple entities including MD, NJ, and Dominion VA threatened to do so (with Dominion following through) around 2020 when PJM expanded its bid floor ("MOPR") to apply to subsidized renewables. ▪ Such exits could provide feasible pathways for states and utilities to lower costs to ratepayers, should PJM see continued high capacity clearing prices.

1) According to PJM executive vice president for market services and strategy Stu Bresler.

Sources: Aurora Energy Research, UtilityDive

Agenda

I. Appendix

2025/26 BRA | 2 LDAs cleared above their parent price, down from 5 in the previous auction

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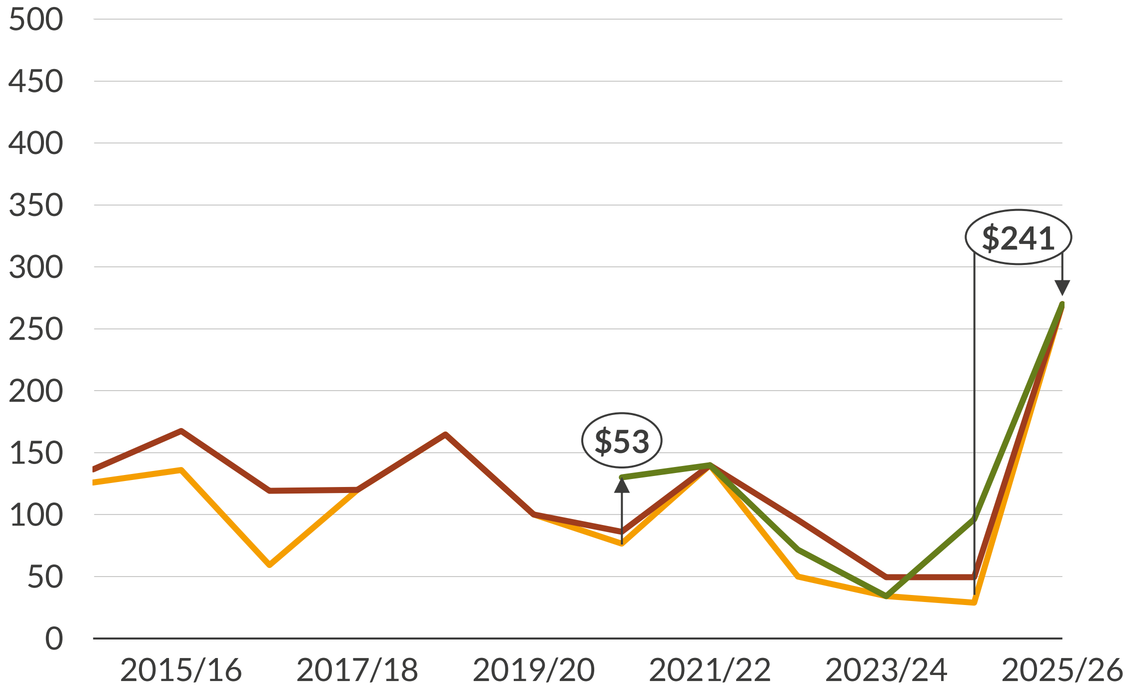
Clearing prices within RTO (for selected LDAs in 2025/26 BRA)

$/MW-day (nominal)

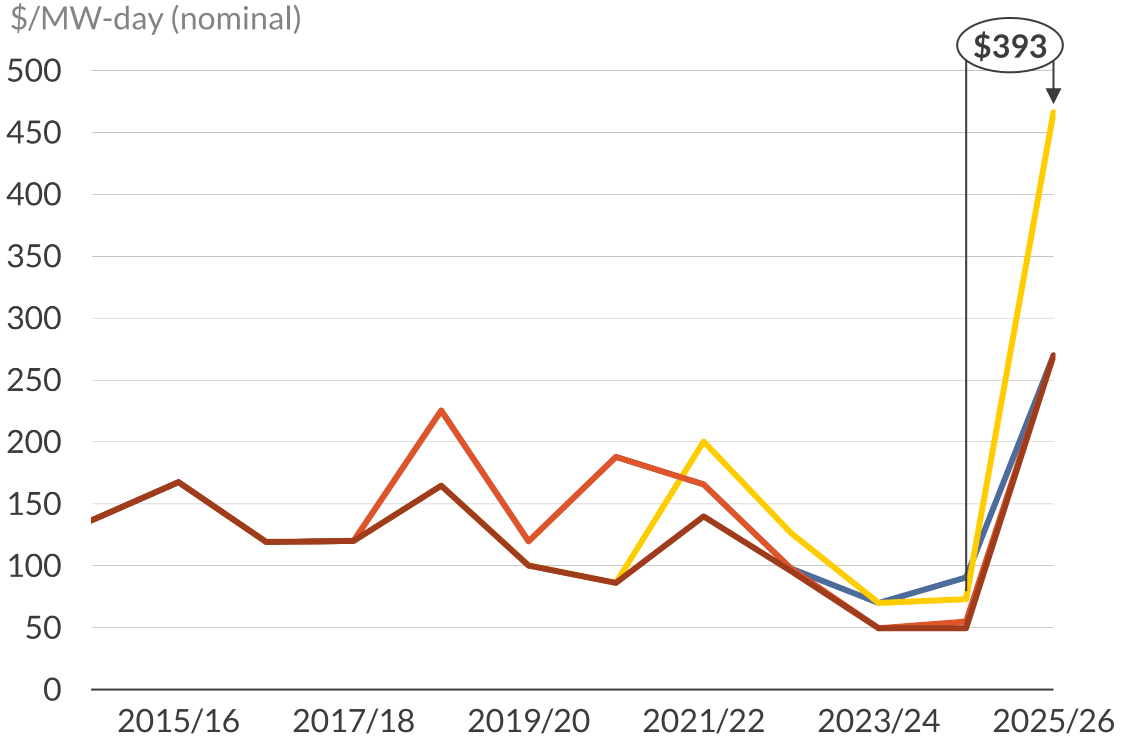


- The 2025/26 BRA saw the largest delta between consecutive RTO clearing prices to date, at $241/MW-day.
- DEOK—modelled as an LDA since the 2020/21 BRA—has cleared above RTO level in 3 out of the 5 prior auctions; however, both DEOK and MAAC cleared at the same level as RTO this time, largely due to RTO's high clearing price.

RTO MAAC DEOK

Clearing prices within MAAC for 2025/26 BRA

$/MW-day (nominal)



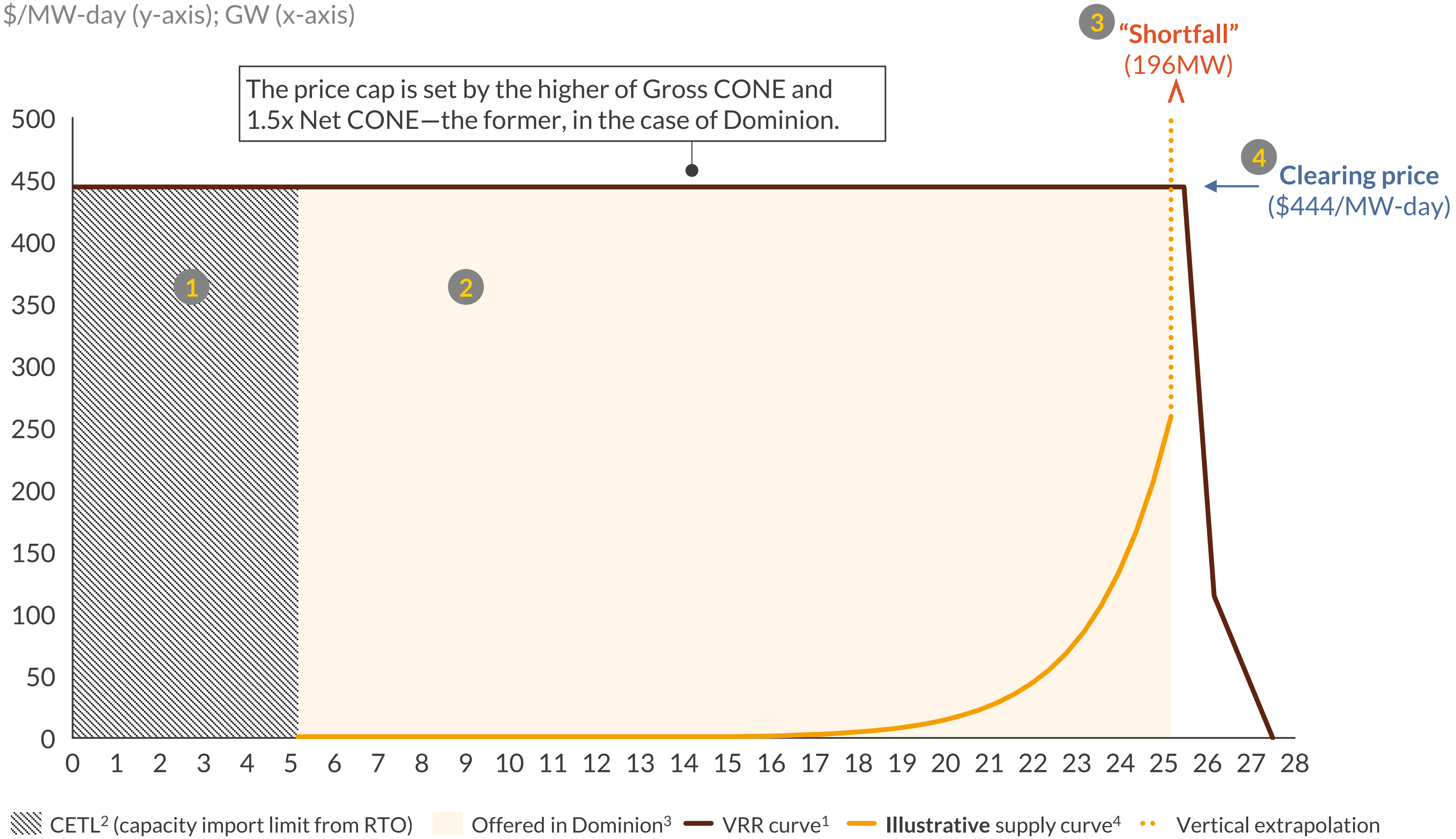
- BGE cleared above the MAAC level in the past 5 auctions, and the trend continued in the 2025/26 BRA too, with BGE clearing $393/MW-day higher than its previous clearing price and $196/MW-day higher than the MAAC clearing price.

MAAC EMAAC BGE DPL-South

Sources: Aurora Energy Research, PJM

2025/26 BRA | Dominion and BGE cleared at their price cap, with total available capacity below any point on the sloped demand curve

Dominion LDA "VRR[1]" demand curve and representative supply stack
$/MW-day (y-axis); GW (x-axis)



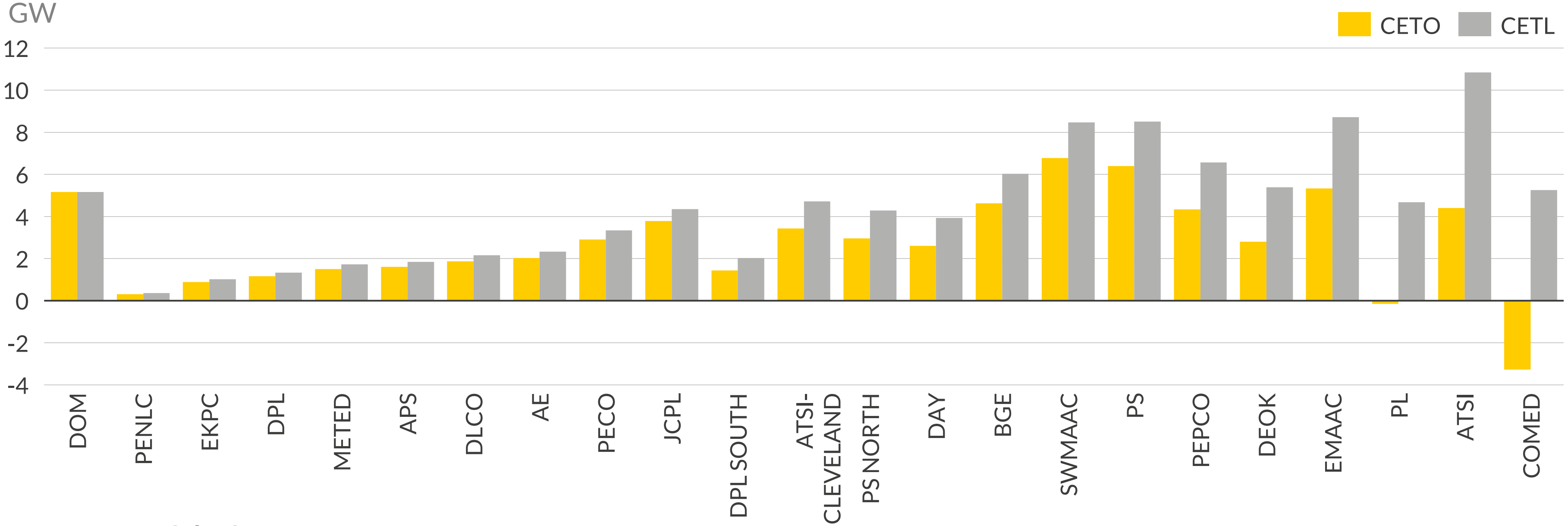
- Available capacity in Dominion LDA can come from two sources:
  1. Capacity imported from elsewhere in the RTO, limited by CETL;
  2. Capacity offered within Dominion (including DR and non-PJM imports).
- 3 The total available capacity (25,167MW) fell nearly 300MW short of the highest point on the sloped portion of the LDA's demand curve, point A (25,463MW).
- 4 As a result, the LDA's price automatically cleared at the LDA's price cap, at $444/MW-day.
- BGE showed analogous shortfall, clearing at its LDA price cap of $466/MW-day.

1) Variable Resource Requirement: PJM's capacity demand curve. 2) Capacity Emergency Transfer Limit. 3) Excluding estimated capacity offered but unavailable to clear because offered as winter-only and no summer-only capacity counterpart was available. 4) X-extent is true to auction results; rest of curve is illustrative, as PJM does not publish bid levels or individual bidder info.
Sources: Aurora Energy Research, PJM

2025/26 BRA | PJM expected Dominion LDA to be highly constrained, assigning it a CETO value nearly identical to its CETL

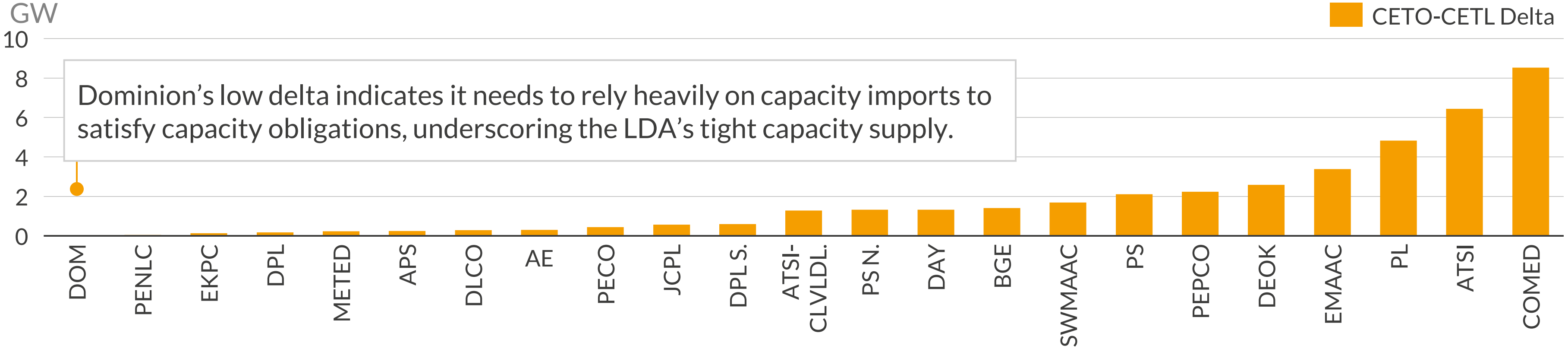
CETL and CETO by LDA

GW



CETL-CETO delta by LDA

GW



- Capacity Emergency Transfer Limits (CETLs) determine how much capacity can be imported into an LDA during peak system stress moments, thus acting as constraints on PJM's cost optimization of the BRA outcome
- An LDA's Capacity Emergency Transfer Objective (CETO) represents the capacity import amount necessary to satisfy loss of load expectation requirements, according to PJM's studies
- Dominion's CETO was nearly identical to its CETL, indicating the LDA's tight capacity supply and resulting need for capacity imports.

Sources: Aurora Energy Research, PJM

Demand deep-dive | VRR shifted out & more vertical; roughly 3 GW UCAP more demand at 2025/26 BRA's $270/MW-day price point

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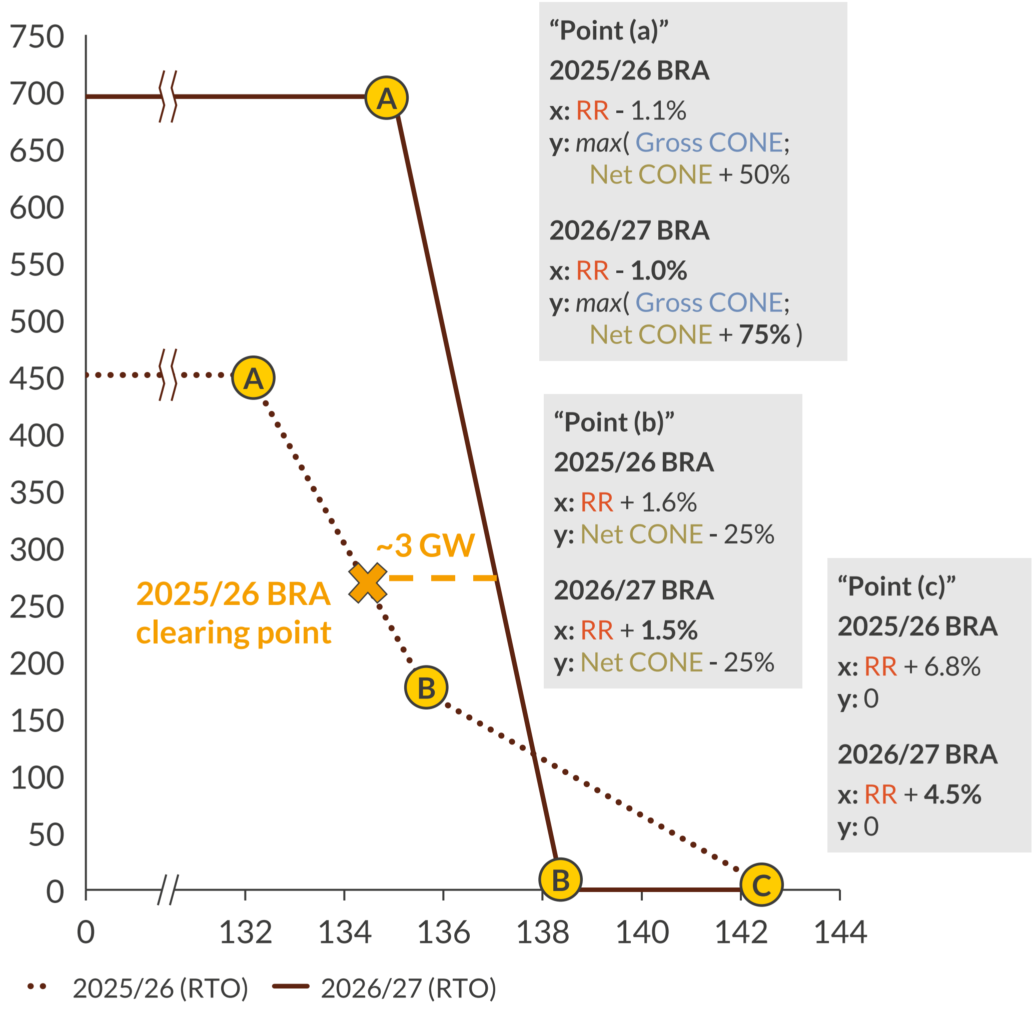
RTO-wide VRR curve[1], incl. point definitions
$/MW-day (nominal), GW UCAP



Key parameter changes for the 2025/26 BRA relative to the previous auction

Parameter	2025/26 BRA (prev. auction)	2026/27 BRA (next auction)	Driver(s)
Reliability Requirement (RR)[2]	144,450MW (133,564MW excl. FRR)	147,246MW (136,360MW excl. FRR)	▪ Increase in forecasted RTO peak load of 3.3GW ▪ Increase in Installed Reserve Margin (IRM) from 17.8% to 18.6%.
Gross CONE	$451.6/MW-day UCAP	$695.8/MW-day UCAP	▪ Shift in the VRR reference resource from combustion turbine to combined cycle. Relative to combustion turbines, combined cycle units are both more capital intensive (increasing Gross CONE) and more lucrative in energy and ancillary services markets (decreasing Net CONE).
Net CONE	$228.8/MW-day UCAP[9]	$0/MW-day UCAP	

1) Variable Resource Requirement—PJM's capacity demand curve, defined by 3 points.

Sources: Aurora Energy Research, PJM

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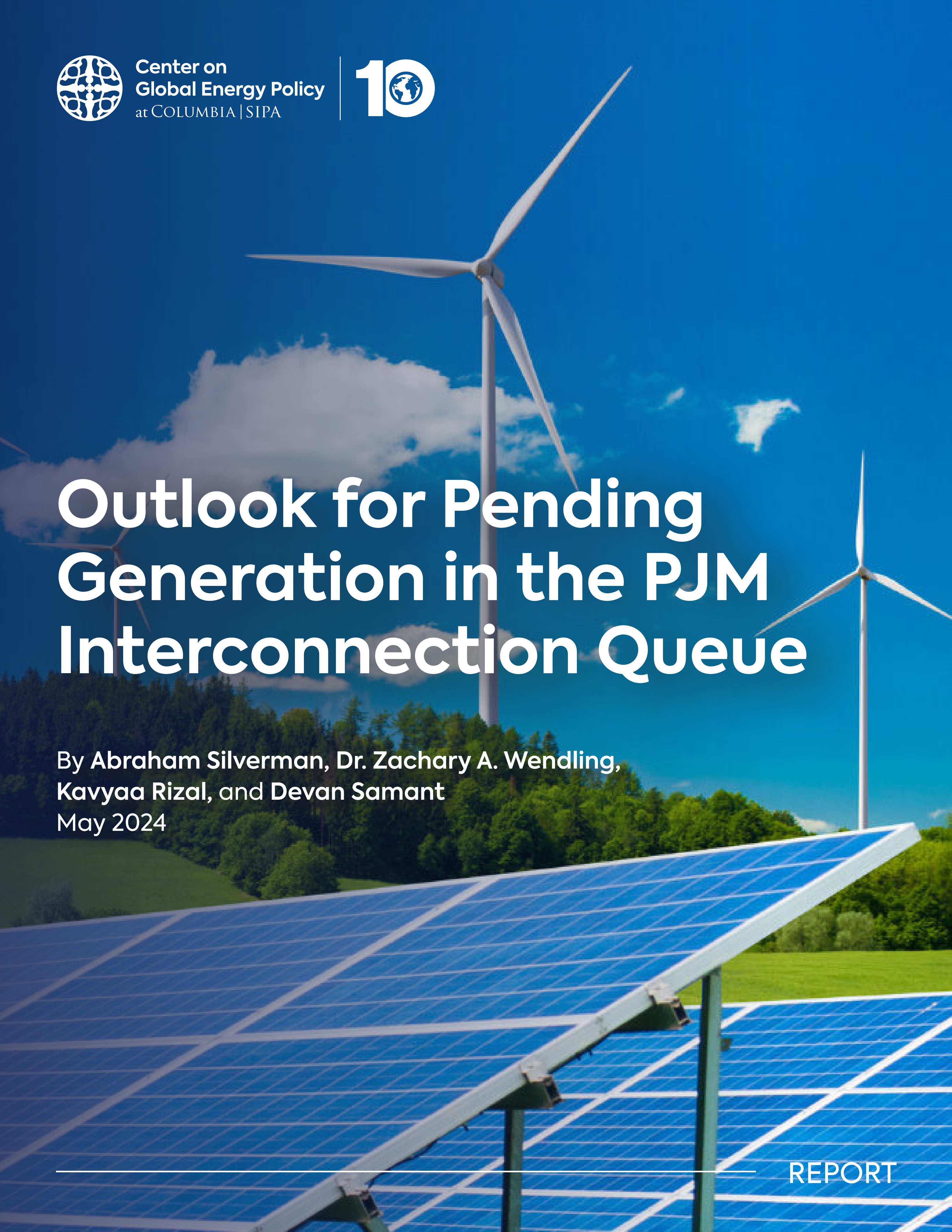
Outlook for Pending Generation in the PJM Interconnection Queue



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10

Outlook for Pending Generation in the PJM Interconnection Queue

By **Abraham Silverman**, **Dr. Zachary A. Wendling**, **Kavyaa Rizal**, and **Devan Samant**
May 2024

REPORT

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Abraham Silverman joined the Center as the Director of the Non-Technical Barriers to the Clean Energy Transition initiative. The Non-Technical Barriers initiative is designed to identify major legal and regulatory bottlenecks to the clean energy transition and then provide state and federal policy makers pragmatic solutions to address those challenges. Major focus areas include Legal and Regulatory Barriers at the state and federal level, Market Rules and Economic Incentives, and Social Acceptance & Just Deployment of Infrastructure.

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Executive Summary

The United States is witnessing rapidly growing interest in clean electricity generation, driven by soaring consumer demand for clean energy and the country's goal to reduce greenhouse gas emissions. In parallel, the time it takes for new, clean generation projects to move from design to execution in the US has lengthened, meaning that the rising interest has not been matched by supply. The country's largest grid operator, PJM Interconnection (PJM), has experienced the most severe delays and backlog in new generation—projects entering the queue today have little chance of coming online before 2030.

It is widely understood that an increasingly lengthy interconnection process, which involves a series of studies and upgrades grid operators must take to ensure projects can connect to the grid safely and reliably, is responsible for this state of affairs. It is not clear how this longer process interacts with other known project development challenges—such as siting and permitting issues, supply chain constraints, and inflationary pressures—and to what extent such interactions may lengthen the timeline for bringing projects online. Understanding these dynamics can help answer critical questions about grid reliability going forward, including whether it will be necessary to delay or cancel the planned retirement of aging fossil fuel-fired generation resources that the new generation is intended to replace.

This report attempts to fill this knowledge gap. It presents results of an author-developed survey of those best positioned to understand the impacts of interconnection process delays: project developers in the PJM market. The key finding from the survey is that PJM's increasingly lengthy interconnection process is exacerbating siting and permitting challenges and leading to knock-on delays in equipment procurement and financing decisions, suggesting the timeline for new generation in this market will likely remain long for the foreseeable future. Given the importance of new entry to keeping prices competitive and maintaining reliability amid the retirement of older fossil resources, PJM will need to find ways to reduce interconnection delays or reconsider when those fossil resources should be retired.

Other notable findings include the following:

- Most developers expect to delay construction milestones or suspend some or all of their development efforts.
- Only 10 percent of developers report that any of their projects will come online within 12 months of receiving an interconnection service agreement, and most report their projects

will require at least 24 months from the time they receive such an agreement to reach commercial operation.

- Developers report very few duplicative interconnection requests, potentially calling into question the conventional wisdom that such projects are a major cause of interconnection delays.
- Over half of the developers who reported withdrawing, suspending, or pausing projects identified interconnection upgrade costs as a significant concern.
- Solar developers report that an outlook of lower value for renewable energy attributes (such as renewable energy credits) was a key factor in their decision to cancel or delay projects, while forward energy prices were less important.
- Offshore wind developers noted that the federal permitting process may require them to consider alternative points of interconnection or alternative turbine sizes, which can create late-stage changes to a project that may not qualify for PJM's traditional process for amending interconnection requests.

Introduction

The Inflation Reduction Act of 2022 and consumer demand for clean energy is driving record interest in new clean generation in the United States. But the time it takes for new clean generation resources to move from design to execution has increased markedly over the past five years, with the median project *completed* in 2023 taking five years from interconnection request to commercial operation.[1] These timelines are only increasing as the interconnection process—that is, the process grid operators go through to ensure that a new generator can connect to the grid safely and reliably—has itself grown from approximately two years in length to five.[2]

The backlog of new generation is particularly severe in the 13-state, plus the District of Columbia, region overseen by PJM Interconnection LLC (PJM), the largest grid operator in the United States, where an influx of new projects, increasing numbers of late-stage project withdrawals, and spiraling numbers of restudies[3] have overwhelmed the queue process, leading to multi-year delays and a freeze in processing new interconnection studies.[4] In consequence, absent significant reforms or market innovations, most projects entering PJM's queue today are unlikely to come online before 2030—and certainly not in the quantities necessary to satisfy demand for clean energy across the region that PJM serves, leading PJM to question whether it can maintain grid reliability.[5]

While experts broadly agree that interconnection delays are hampering the clean energy transition,[6] there is a relatively poor understanding of how these delays are interacting with other recognized development challenges, such as siting and permitting issues, supply chain constraints, and inflationary pressures, and how those interactions affect the timeline for developers to bring projects online.[7] As policymakers debate whether to delay or cancel the planned retirement of aging fossil fuel-fired generation resources due to concerns that new generation will not be ready to take their place,[8] having a grasp of these relationships and the commercial outlook for how long it takes to bring new resources to market could prove critical.

In an attempt to address this knowledge gap, the authors conducted a survey of developers with projects in the PJM interconnection queue. Responses were received from 30 independent developers representing 69 total projects across a range of generator technology types that entered the queue between 2017 and 2023 and reached an advanced stage of the interconnection process by June 2023. The authors also conducted limited follow-up interviews with developers.

The report begins by contextualizing the PJM backlog and explaining its implications for grid reliability. It then introduces the survey of developers and presents the survey results. The report concludes by analyzing the policy implications of the findings and offering a set of recommendations to policymakers and other stakeholders should they wish to resolve the delays caused by the interconnection process in the regions PJM serves and beyond.

The PJM Backlog and Its Implications for Reliability

Explaining the PJM Interconnection Queue

At the end of 2023, 2,600 gigawatts (GW) of generation and energy storage were waiting to connect to the grid nationwide—more gigawatts of generation than currently operate in the entire United States.[9] Zero-carbon resources, including wind, solar, and energy storage, comprised more than 90% of this capacity.[10] Increasing delays in the timeline for interconnection of new resources are well documented, with the average project now taking approximately five years to get through the study process, complete any necessary grid upgrades, and reach commercial operation.[11] These delays strongly impede the deployment of clean energy resources, harming economic competition, market efficiency, and reliability. They also blunt the impact of the Inflation Reduction Act of 2022, which provides incentives for new projects to reach commercial operation within a decade. The availability of these incentives is expected to drive significant reductions in greenhouse gas emissions through the remainder of the decade, but will only do so if generation is actually able to come online.[12]

Efforts to accelerate the interconnection study process are well underway at the Federal Energy Regulatory Commission (FERC). FERC's landmark Order No. 2023,[13] for instance, required all FERC-jurisdictional utilities to adopt new interconnection queuing rules into their tariffs. Regional electricity market operators, including PJM, are provided additional flexibility to propose rules tailored to their specific needs. PJM's compliance filing, along with that of the nation's other independent system operators (ISOs) and regional transmission organizations (RTOs), are due in late spring 2024.

The interconnection queue in PJM mirrors the national trend, where over 2,600 gigawatts of new generation is stuck in a queue. The number of new projects entering the PJM queue tripled between 2018 and 2021, and the total capacity of pending projects is now over 200 GW.[14] The surge in projects led PJM to freeze its interconnection queue in May 2022.[15] According to PJM's Independent Market Monitor, the FERC-recognized independent auditor for the PJM market, "as of December 31, 2023, 268,472.8 [megawatts] were in generation request queues in the status of active, under construction or suspended."[16] This represents "a decrease of 19,019.9 MW (6.6 percent) from the 287,492.7 MW at the end of 2022."[17] Approximately 75% of the generation awaiting study is zero-carbon,[18] compared to the current approximately 160 GW capacity of the entire existing PJM system. Just over 4,400 MW of new generation entered service in 2023. Of that generation, 70% was combined cycle or combustion turbine gas-fired resources, 20% was solar, 6.5% was wind, and the remainder was battery and solar as well as storage units.[19] Although PJM is implementing emergency reforms to its interconnection program, it expects that alleviating the backlog will take several years.

In late 2023, PJM stated that it "expected to clear 300 new generation projects totaling [26 GW] in 2024" and that "another [46 GW] of nameplate generation capacity in projects...should clear PJM's study process and be ready for construction by mid-2025, for a total of [72 GW] of projects."[20] Thus, even completing tens of gigawatts of interconnection studies annually still leaves PJM significantly behind the voracious consumer demand for clean energy.

Implications for Reliability

The speed at which projects move through the PJM interconnection queue and the rate at which those projects come online have major implications for the reliability of the electric grid. It is an electrical industry axiom that a reliable electric grid requires the availability of sufficient generation resources to meet electricity demand on peak days, plus an appropriate reserve margin. In practical terms, this "balance sheet" approach to reliability means that as existing generation resources retire, they must be replaced with resources of comparable capacity.

In 2023, PJM officials expressed concern that new resources may not reach commercial operation in sufficient quantities to replace retirements in the existing fleet.[21] As PJM put it, "the amount of generation retirements appears to be more certain than the timely arrival of replacement generation resources, given that the quantity of retirements is codified in various policy objectives, while the impacts to the pace of new entry of the Inflation Reduction Act, post-pandemic supply chain issues, and other externalities are still not fully understood."[22] PJM's Independent Market Monitor likewise stated that "the markets face a challenge from potentially high levels of expected thermal generator retirements, with no clear source of replacement capacity or the fuel required for that capacity."[23]

One of the complicating factors identified in PJM's Energy Transition Report is that the reliability value of a new generator is a function of both the size (or nameplate) of the generator and how it is likely to operate during periods of stress on the grid. PJM notes that it would take just over 107 GW (nameplate) of new renewable and battery resources to provide 30 GW of reliability value.[24] The reliability value (or "capacity accreditation" in PJM lingo) of a resource is set by PJM based on complicated probabilistic models conducted by PJM,[25] often referred to as Expected Load Carrying Capability (ELCC).[26] The ELCC value is intended to reflect the likelihood that any given generation resource will be available when needed and accounts for factors such as correlated outages of natural gas resources during cold weather[27] or correlated output of solar resources. The result is that PJM's balance sheet reliability analysis is likely to evolve over time as system conditions change, which makes long-term estimates of grid reliability challenging.

Currently, PJM relies on a mix of largely fossil fuel-fired and nuclear generators to meet its reliability needs. However, PJM forecasts that 40 GW, or 21% of its total installed capacity, will retire by 2030.[28] This estimate includes 12 GW of previously announced retirements, 25 GW of retirements driven by federal and state environmental policies, and 3 GW of projected economic retirements.[29] PJM's Independent Market Monitor puts the potential retirement figure even higher, noting that "although the exact numbers may vary, an estimated total of between 24,000 MW and 58,000 MW of thermal resources are at risk of retirement."[30]

Among the policies driving these retirements, several are notable:

- Illinois's Climate and Equitable Jobs Act mandates the retirement of 5.8 GW[31] of coal-fired and high-emitting gas resources.[32]
- A trio of rules from the US Environmental Protection Agency (EPA), namely, the Coal Combustion Residuals, Effluent Limitations, and Good Neighbor Rules, will result in the retirement of approximately 10 GW of generation retirements.
- New Jersey's Carbon Dioxide Rules will result in approximately 3 GW of generation retirements.[33]

While PJM has weathered similar scale retirements in the past (particularly during the mid-2010s, in response to Obama-era EPA rules), the expected replacement schedule is one of the more substantial transitions away from fossil generation in its history.[34]

PJM has highlighted the two dominant drivers of uncertainty about future reliability: the speed at which new generators are proposed and the rate of success for generators currently in the interconnection queue. PJM selected several different measures of the volume of new generation currently in the queue that is likely to reach commercial operation, and made additional assumptions about how much new generation is likely to enter the queue between 2023 and 2030. PJM's "High New Entry" scenario projects sufficient new entry to offset resources anticipated to retire.[35] However, PJM's "Low New Entry" scenario reaches the opposite conclusion, namely, that insufficient new generation will come online to keep up with anticipated retirements. The result would be either higher prices for consumers or a reliability crisis. Only PJM's "High New Entry" scenario adds enough new generation to almost entirely offset the anticipated retirements of fossil resources, even after applying PJM's new ELCC methodology.[36] In its December 21, 2023, update, PJM stated that "at the end of 2023, about [40 GW] of projects that had completed the

PJM study process had yet to move through construction, due to issues including siting, supply chain and financing."[37]

While numerous parties have identified concerns with PJM's analysis—in some cases, calling into question its key conclusion[38]—the specter of a reliability crisis continues to drive sharp energy policy debates. Surveying developers with projects currently in the interconnection queue sheds new light on the dynamics behind this uncertainty.

Study Design

Generation developers have a unique perspective on the challenges of bringing new resources to market, including elongated interconnection study processes, siting and permitting, inflationary pressures, market outlook, and delayed supply chains. The authors identified a range of possible project challenges based on their experiences and conversations with developers and PJM, and then prepared a survey of 27 questions to assess which, if any, developers saw as most salient in the development process.

When respondents designated challenges as highly significant to their projects, the survey prompted them with more specific questions about those challenges. The survey also included questions about how the hurdles presented by atypical events, such as the COVID-19 pandemic and related supply chain and inflationary issues, compared with the more typical aforementioned challenges. Several questions allowed respondents to identify other challenges not identified in the survey. Finally, survey participants were invited to participate in informal follow-up interviews.

Sample

Because the authors were interested in projects that could potentially come online in the next several years, the survey focused on projects that entered PJM's interconnection queue between January 1, 2017, and May 16, 2023. The sample was then further narrowed down to projects at an "advanced stage" of the interconnection process as of June 1, 2023, meaning those that had just started the Facilities Study process, completed a Facilities Study, or tendered or executed an Interconnection Service Agreement (ISA) or the equivalent.[39] Throughout the analysis, the term "project" is used to refer to a single proposed generation project or generator uprate that was assigned a queue position by PJM.[40] The term "developer" or "project sponsor" refers to the ultimate upstream corporate parent. Each developer's parent was identified by cross-matching the name of the specific development project with the upstream parent in FERC filings, interconnection agreements, and/or general web searches. In cases where two upstream owners are partners for a project, both were invited to participate in the survey.

Data on projects was obtained from PJM's New Services Queue. The latter includes project technology, location, and progress through the interconnection queue,[41] as well as links to ISAs and the interconnection studies performed by PJM, which provide additional information not available in the database itself. While these study documents are a mix of machine-readable and non-machine-readable data, web scraping techniques, optical character recognition, and independent research were used to identify developer names and contact information. The survey team also worked with PJM and a variety of business- and policy-oriented trade associations to alert developers to the existence of the survey and solicit participation.

Table 1 contains a description of the projects in PJM's interconnection queue and those in the sample. In total, 496 projects listed in the New Services Queue met the survey qualifications. Of those, project-level data could be extracted for 412 projects and email addresses obtained for 332 projects across 89 developers. The 412 projects had an estimated nameplate capacity of 30 GW. In total, 30 developers representing separate corporate parents substantially completed the survey, divided evenly between two outreach methods. One method involved sending the survey via email to 224 distinct email addresses that had been compiled. One hundred of the emails were opened, and 15 surveys were substantially completed. The second method involved sharing a generic link to the survey to other developers that met the survey qualifications through webinars and informal communications. Fifteen respondents substantially completed the survey using the generic link.

Table 1: Description of sample size and participation

Criteria	Description	Projects	Developers	Nameplate capacity (GW)
Eligible	Entered queue January 1, 2017–May 16, 2023 *and* As of June 1, 2023, either (1) started or completed Facilities Study, *or* (2) tendered or executed Interconnection Service Agreement	496	–	–
Described	Project-level information available from PJM's New Services Queue databases and online sources	412	–	30
Contacted	Discernable email contact information available	332	89	26.4
Responses	Completed survey	69	30	7.1

Respondents to the generic survey were included in the data set if they stated that they had a project that met the survey qualifications. In total, 30 responses in which at least one substantive portion of the survey was completed were received, including from both developers who responded via email and those who used the generic version. Respondents spanned 69 projects that could be tied to specific queue positions, totaling 7.1 GW of generation or storage, or approximately 24%

of the nameplate capacity and 17% of the projects meeting the qualifications for participation in the survey.[42] The 69 project tally likely undercounts total project participation given that some developers represent projects that were not captured by the authors' automated electronic scraping.[43] When asked to self-report the number of eligible projects they represent, developers reported additional projects. The lower, more conservative figure was used to calculate the total survey participation rate. Some questions directly asked the respondent how many projects they were developing. In such cases, the number of projects identified by the developer was used.

Survey

The online survey[44] asked questions about the following topics:

- Siting or permitting considerations at the federal, state, and local levels.
- Length of the interconnection process, both including and excluding new transmission construction.
- Expectations for commercial operation dates.
- Supply chains.
- Tariffs.
- Labor issues.
- Commercial outlook, including for energy, capacity, and environmental attributes.
- Implications of inflation on market conditions related to cost of capital, financing, tax equity, or other financing metrics.
- Regulatory changes related to Effective Load Carrying Capability rules.

The survey asked developers to identify challenges associated with projects that were "actively in development" as well as projects that were "withdrawn from the PJM queue, put into suspension, or for which your firm paused or ceased development." Unstructured follow-up interviews were also conducted with personnel from selected firms to better understand the challenges they are facing and obtain additional context.

Interviews

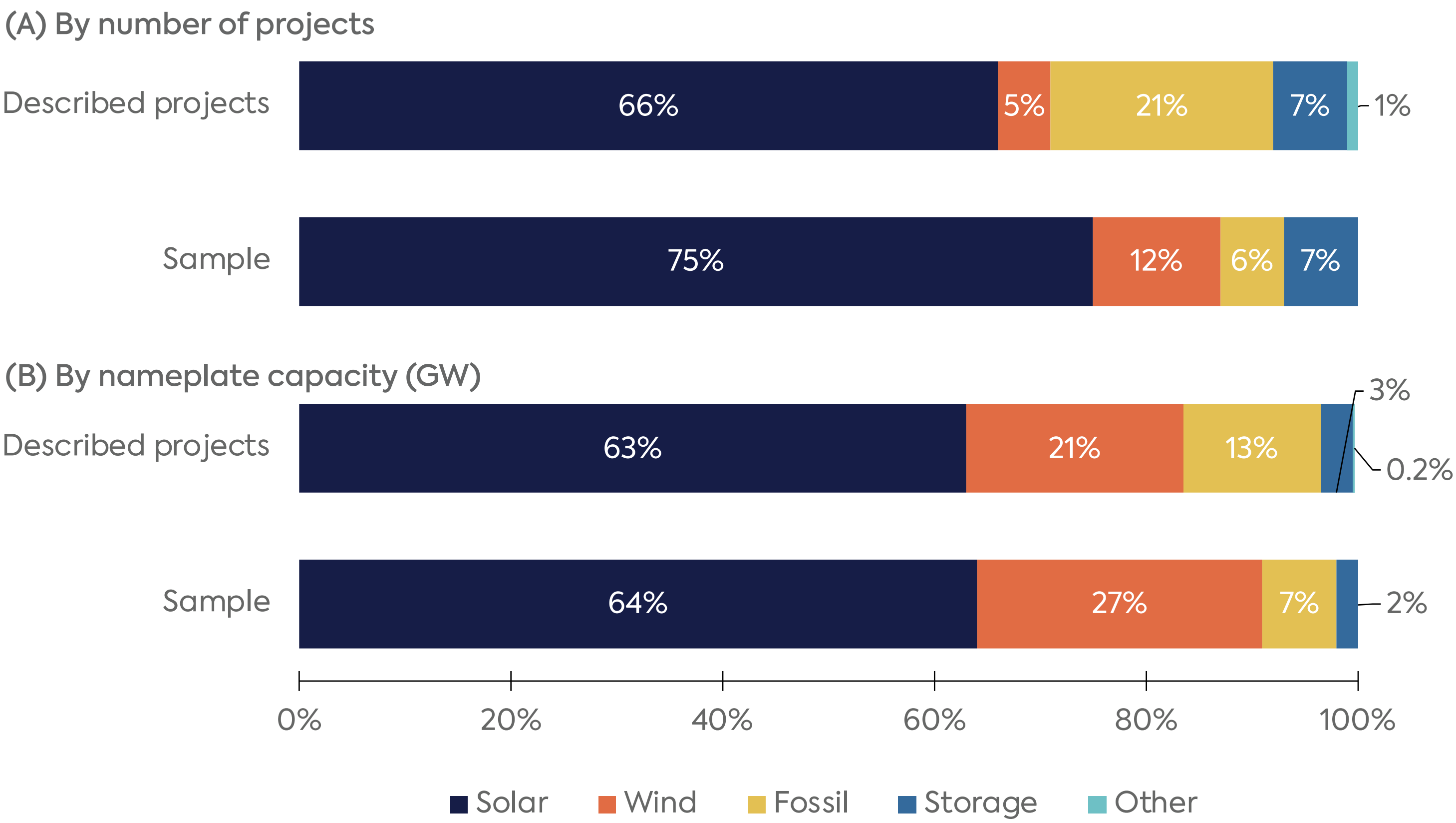
Developers with eligible projects were also invited to participate in unstructured interviews. Six total interviews were conducted. Most interview participants also participated in the survey process, although one firm with eligible projects participated only in the interview process. The interviewees provided additional context for as well as explanations of their experience with the interconnection process.

Results

Descriptive Statistics

Figure 1 shows that the population of described projects (see Table 1) is largely solar or hybrid solar with storage (66%), compared with 75% in the sample, which underrepresents fossil fuel projects and overrepresents wind projects. Likewise, by nameplate capacity, 63% of described projects in the interconnection queue are solar or solar with storage, compared with 64% of the capacity in the sample. The sample contains more wind (27% vs. 20%) and less fossil fuel (7% vs. 13%) than the population's capacity.

Figure 1: Comparison of percentage composition of the sample (n = 69, 7.1 GW) to all described projects (N = 412, 30 GW) by number of projects and nameplate capacity



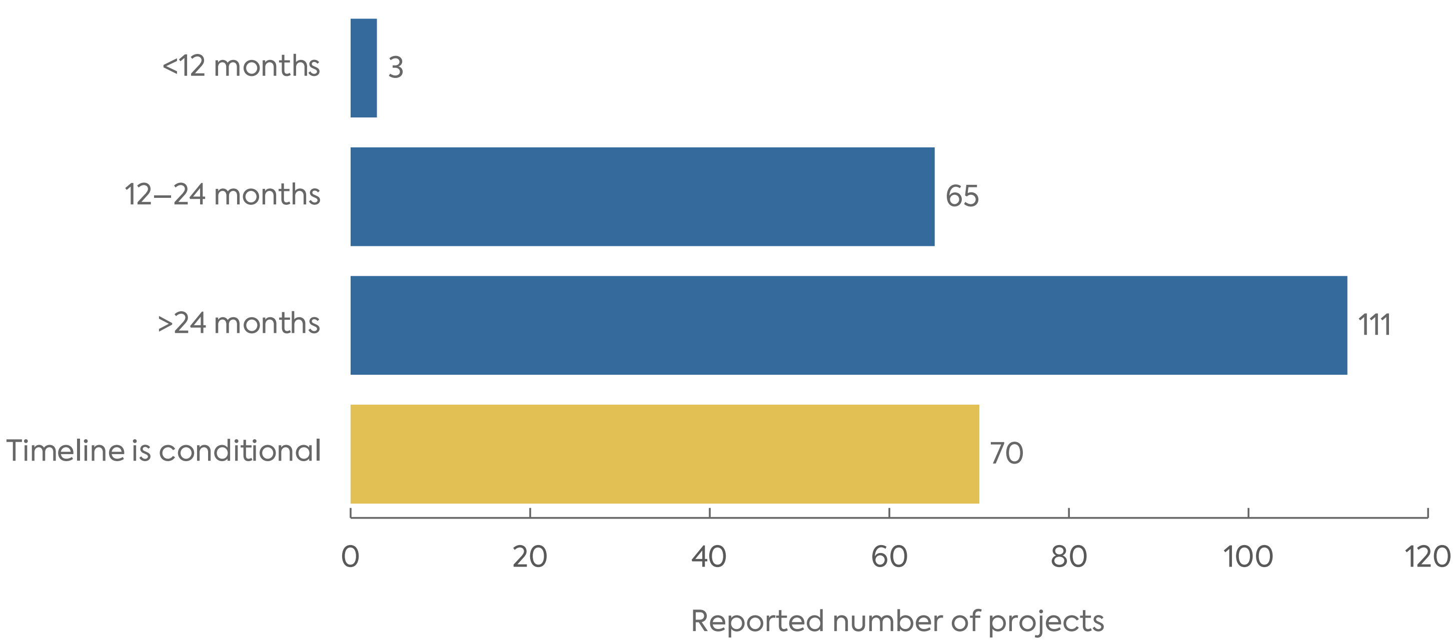
Note: Solar and wind projects include those with and without storage.
Source: Authors' analysis.

Timeline for Bringing Projects Online

The rate at which new interconnection projects make it through the queue and eventually reach commercial operation represents the difference between a reliability crisis with sub-10% reserve margins and a healthy grid.[45] To better understand the developers' outlook on timing, the survey asked how long it would take for each of their projects to reach commercial operation from the time they received an ISA. Eighteen developers responded to this portion of the survey (Figure 2).

Figure 2: Expected timeline for projects if developers received an Interconnection Services Agreement today, based on 18 respondents

"If all your projects received an Interconnection Services Agreement today, how many would reach commercial operation in the following time frames?"



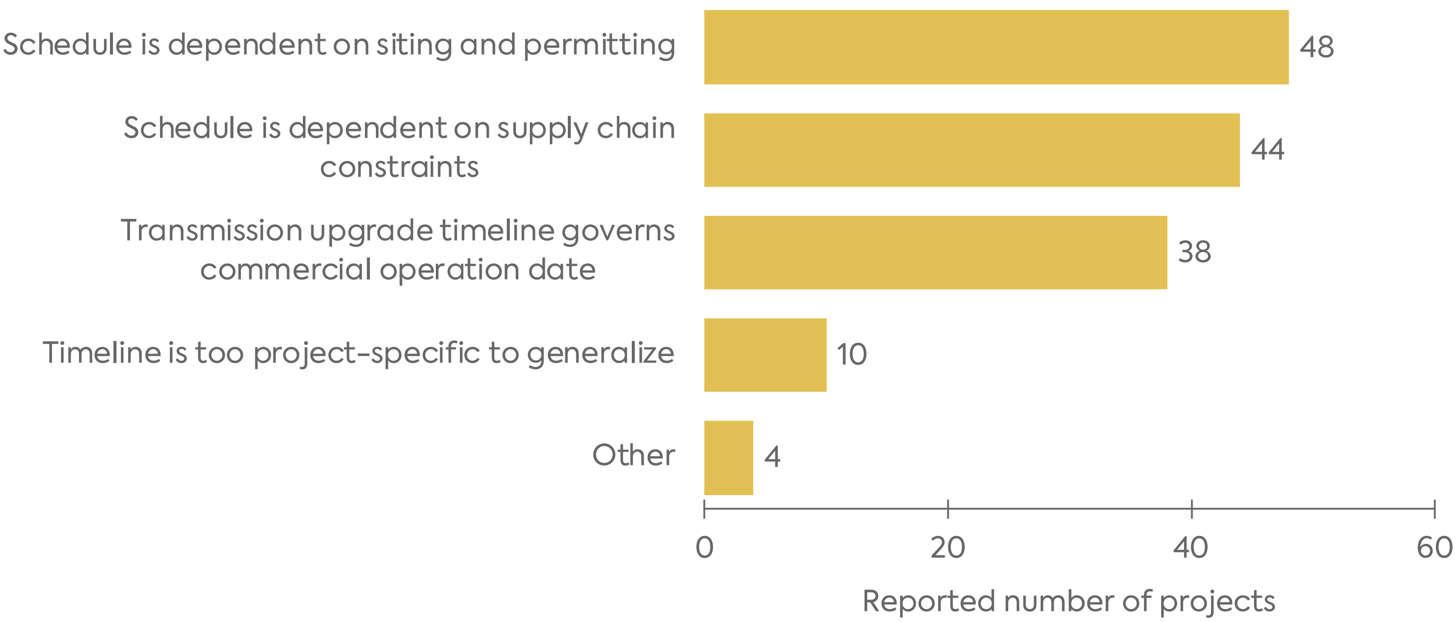
Source: Authors' analysis.

Note that the number of projects was self-identified by the developers, which resulted in a higher number of projects. The three projects with the fastest timelines were an uprate to a natural gas facility, a wind farm, and a solar farm. Medium-term projects included wind, solar, and natural gas resources. Projects expected to take longer than 24 months spanned multiple technologies.

Numerous respondents also said that timeline estimates were "conditional" on project-specific factors. To explore this aspect, the survey asked them to indicate how many of their projects depended on five different factors that were purposefully selected to explore the relative role of siting and permitting, supply chain, and network upgrade timelines (Figure 3).

Figure 3: Factors affecting projects with conditional completion timelines, based on 8 responses

"Thinking about your projects that have uncertain timelines, upon which of the following factors does the schedule depend?"



Source: Authors' analysis.

Siting and permitting was the largest source of uncertainty, followed closely by supply chain constraints and transmission upgrades. Developers who selected "other" or added commentary to their responses identified state renewable energy incentives and the ability to comply with Ohio's Domiciled Worker Rule as major sources of uncertainty, while another identified state policy changes.[46]

Expected In-Service Dates

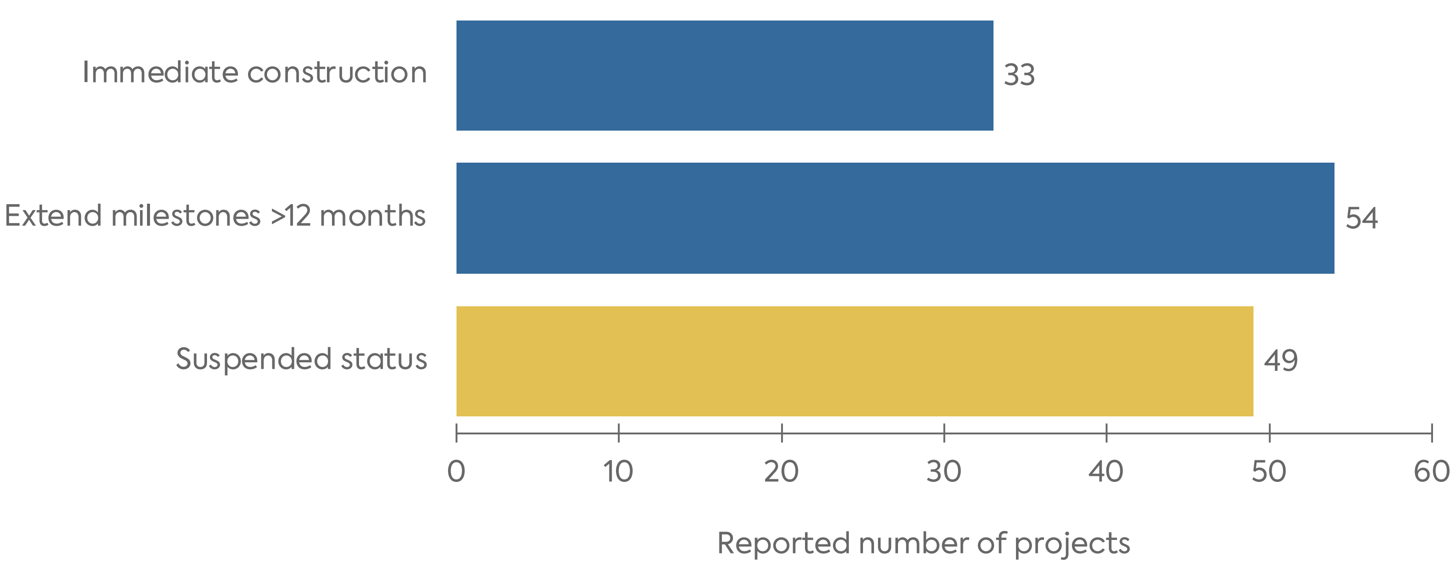
Expected in-service date is an important metric of the health of projects in the PJM queue. In-service dates are a function of two different but highly interrelated processes: the developer's construction of the facility itself; and the construction of network upgrades, or the grid enhancements necessary for the interconnecting utility to receive the power onto its transmission system. Generally, these upgrades must be completed before unrestricted commercial operations can commence. Each ISA issued by PJM includes a set of "construction milestones," applicable to both the developer and the interconnecting utility, that describe when each entity expects to complete its work.[47] If a developer misses its milestones, PJM can remove the project from its interconnection queue.

Because utility and developer construction activities often overlap or are dependent on each other, the PJM process allows developers to extend the milestones, which simply postpones their obligation to meet them, or to request that PJM put their project into "suspension," which allows the developer to pause construction activities until the project is restarted or canceled. In each case, the utility's milestones are revised accordingly. Milestones can also be extended by the transmission-owning utility to reflect delays in procurement of equipment, such as high-voltage transformers, or construction of network upgrades.

To explore how quickly developers expect to be able to begin construction on their projects, the survey asked whether they would commence construction of new facilities or take another action that would delay construction (Figure 4).

Figure 4: Next steps for projects receiving an Interconnection Services Agreement today, based on 27 respondents

"If you were to receive an Interconnection Services Agreement today, which of the following next steps would you be most likely to take?"



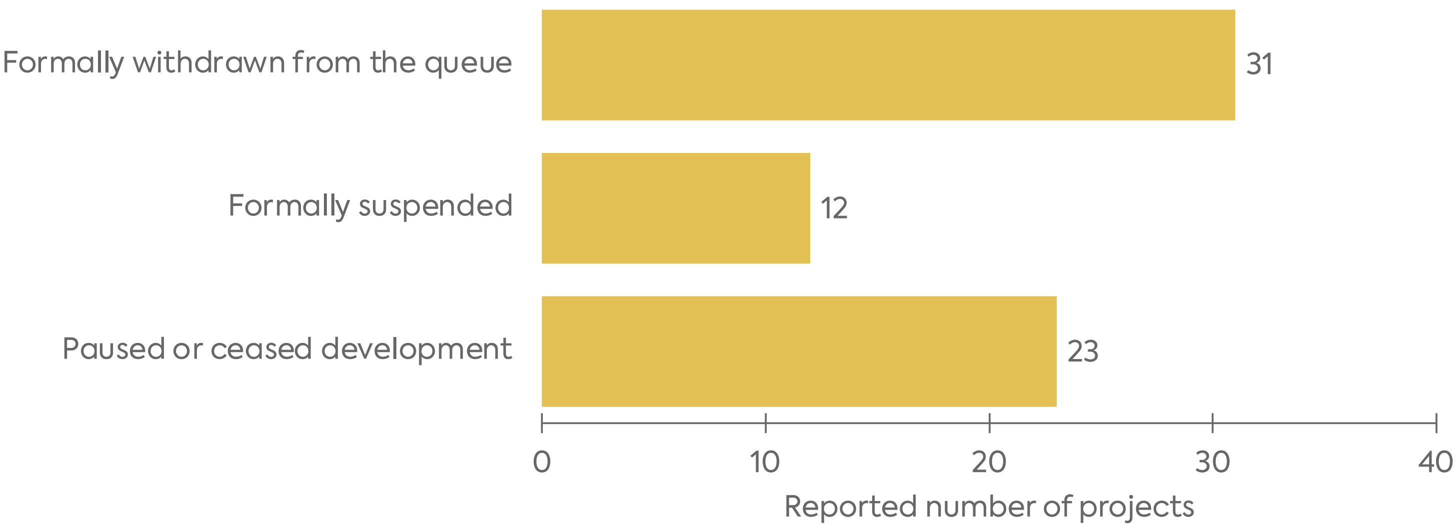
Source: Authors' analysis.

Eleven developers identified a total of 33 projects on which they anticipate commencing construction immediately after receiving an ISA, including uprates to existing natural gas facilities and solar resources. Eight developers representing 54 projects stated that their next step would be to extend milestones by more than 12 months. Another eight developers representing 49 projects across only wind and solar technology types indicated that they would put projects into suspended status. Several developers indicated that they would extend milestones and then likely put the project into suspension. During interviews, some developers indicated that projects would immediately proceed to final engineering. One developer explained, for instance, that once an ISA is received, the project would go to either a senior executive or the board of directors for a Final Investment Decision. The developer cautioned that taking a project to Final Investment Decision can be a lengthy process, as it typically requires identifying equipment and third-party financing arrangements before any determination can be made.

Another significant issue is the fate of projects that received construction milestone extensions or were suspended. Historically, such projects have remained in the interconnection queue despite not being under active development. Because studying a project consumes PJM resources regardless of its commercial prospects, PJM recently reformed its interconnection rules to remove these stalled projects from its queue by inserting two new requirements: increased maturity and financial security postings.[48] The survey asked developers how many of their projects were currently formally suspended, informally paused, or withdrawn from the queue. Developers report that approximately half were formally withdrawn from the queue (31/66) and 12 were formally suspended, in accordance with the new PJM rules. Twenty-three projects were informally paused by the developer (Figure 5).

Figure 5: Status of projects that received milestone extensions or were suspended, based on responses from 18 developers

"How many of your projects were withdrawn from the interconnection queue, put into suspension, or for which your firm paused or ceased development?"



Source: Authors' analysis.

The survey also provides insight into the question of how often developers submit multiple, marginally different interconnection queue requests for the same project. The extent to which these duplicative requests slow down PJM's efforts to complete interconnection studies has been hotly debated,[49] and several of PJM's recent queue reforms were designed to eliminate them. In the sample, only one developer identified an interconnection queue request that had been suspended or paused because it was extremely similar to another project with a separate queue position. Given this issue has been a major theme in PJM discourse, it was surprising to find only a single instance of it among the all the projects in the survey,[50] though it is possible that developers are unwilling to self-report filing a duplicative or speculative interconnection request.

Evaluating Major Challenges

Projects may face a variety of major challenges to successful completion. The authors identified challenges to be included in the survey based on their experience with interconnection challenges, review of ongoing interconnection reforms, and informal discussions with developers. Challenges were divided into two categories: non-financial barriers and financial and business barriers (Table

2). The survey also allowed developers to highlight specific aspects of these challenges and identify other challenges that were not included in the survey.

Table 2: Major challenges to projects in the interconnection queue

Non-financial barriers	Financial and business barriers
• Siting or permitting considerations at the federal, state, or local level. • Length of the interconnection study process (not including construction of network upgrades or interconnection facilities). • Length of the construction timeline for network upgrades or interconnection facilities or uncertainty around that timeline. • Supply chain concerns unrelated to solar tariffs or import restrictions. • Supply chain concerns related to solar tariffs or import restrictions. • Ability to establish site control. • Workforce or labor shortages. • Other (please describe).	• Ability to win a competitive solicitation or comparable process. • Lack of an offtake agreement. • Inflationary pressures related to equipment procurement costs. • Change in anticipated revenues from the capacity and/or energy market. • Change in financial market conditions related to cost of capital, financing, tax equity, or other financing metrics (separate from equipment procurement costs). • Change to state regulatory policy that affected value of environmental attribute or incentive programs. • Change in corporate strategy or risk appetite unrelated to a specific project. • Other (please describe).

Developers were asked to rate these major challenges on a five-point scale:

1 = The factor has no impact on the development of project(s)
2 = The factor has a small impact on the development of project(s)
3 = The factor has a moderate impact on the development of project(s)
4 = The factor has a major impact on the development of project(s)
5 = The factor has a decisive impact on the development of project(s)

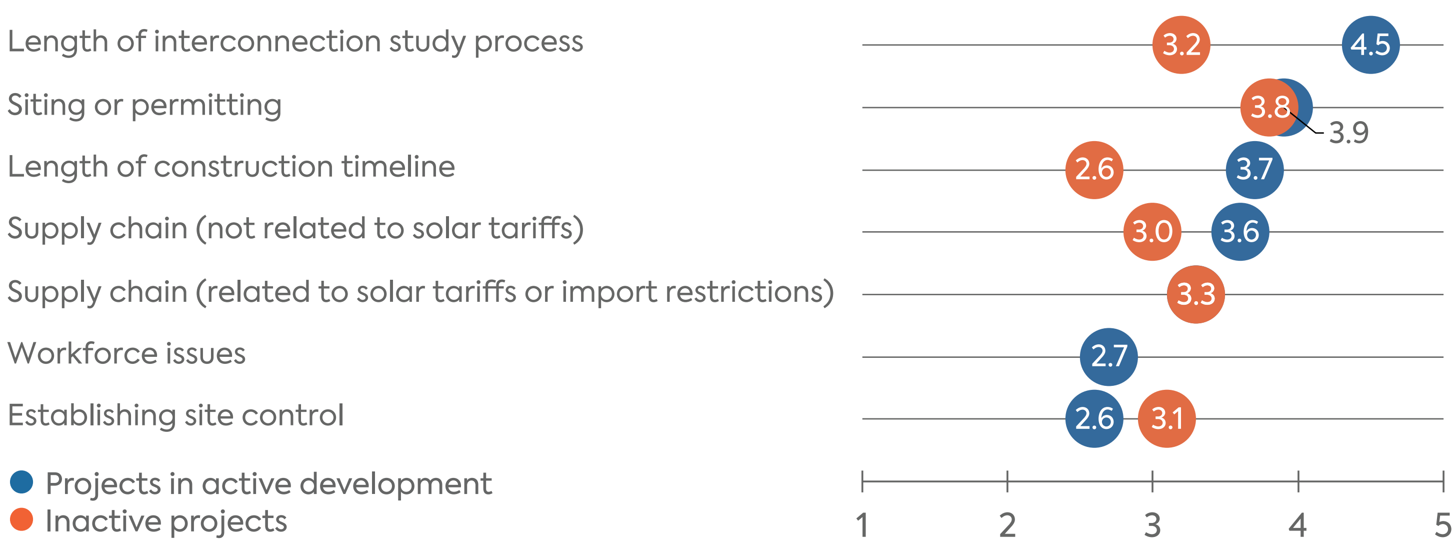
Developers repeated this rating separately for two kinds of projects: (1) those in active development, which were defined as "your company's project or projects that reached the Facilities Study phase or that were tendered an Interconnection Service Agreement or the equivalent"; and (2) projects that have "been withdrawn from the PJM queue, put into suspension, or for which your firm paused or ceased development."

Non-Financial Barriers to Project Development

To assess non-financial barriers, the survey asked respondents to think generally about projects that were actively in development as well as those that are inactive (i.e., withdrawn from the queue or put into suspension by PJM, or paused or ceased development by a firm). In general, respondents rated non-financial barriers as more significant for projects in active development than for those that are inactive, potentially because projects that did not pencil out financially never reached the stage where non-financial barriers were relevant. The greatest difference between these project types related to length of construction timeline, which developers of active projects rated 3.7 out of 5 and developers of inactive projects rated 2.6, the lowest of any factor. For active projects, length of interconnection study process led with an average rating of 4.5 out of 5, indicating a significant burden on the rate of deployment for new energy resources. Respondents rated workforce issues (2.7) and establishment of site control (2.6) as the lowest barriers for active projects (Figure 6).

Figure 6: Average ratings on a five-point scale (5 = decisive impact, 1 = no impact) of non-financial barriers to projects in active development or inactive projects, based 23 respondents for active projects and 15 respondents for inactive projects

"Thinking about your projects that are {inactive / actively in development}, please rate the following factors associated with the interconnection process, siting, permitting, or supply chains on {your decision(s) / how much of a challenge they are to the project(s)}."



Note: "Inactive" includes projects that PJM has withdrawn from its queue or put into suspension, or that the firm has paused or ceased development on. Respondents with inactive projects were not asked about workforce issues.
Source: Authors' analysis.

Length of Interconnection Process

During the interview process, and in response to the open-ended survey questions, several developers explained that uncertainty over the length of the study process was leading to longer siting and permitting timelines. Specifically, developers noted that local siting approvals and permits often lapse after a year or two and that many permits require that the developer start construction within a specified amount of time and then "make continuous progress" for that permit to be maintained. They further noted that when the length of the interconnection study process is knowable, they typically synchronize it with the permitting/siting process, but the uncertainty associated with the current interconnection process has led them to wait to submit new permitting or siting applications until they receive an Interconnection Services Agreement from PJM. As one developer stated during the interview process, "The permitting aspect is an issue. Some people start on both permitting and interconnection at the same time. But we've taken the approach that we're going to wait and see and start permitting at the end."

In the interviews, other respondents identified difficulties in maintaining "site control during extended and uncertain interconnection processes," explaining that options, which give the developer the exclusive right to purchase the property in the future, or other long-term property arrangements were expensive to maintain. One developer also expressed concerns about PJM's approach to deadline enforcement, asserting that "tariff compliance is one-sided; projects sit in limbo for 18 months, and then PJM finally gets in touch on a Friday afternoon and gives you three business days [to make major commercial decisions]."

Concerns about interconnection timelines applied to all technology types, with solar developers slightly more concerned (average score of 4.8) than fossil fuel developers (average score of 4.0). Concerns about the length of the interconnection process were likewise cited as a "major" or "decisive" factor by almost half of developers with paused, suspended, or withdrawn projects.

Siting and Permitting

Seven of the 10 developers who identified siting and permitting as a major non-financial barrier (covering a total of 47 projects) deemed siting concerns as a "decisive" or "major" factor in the cancellation of one or more projects, with many citing county-level siting and permitting challenges as the primary factor in either commentary or during the interview process. Other developers specifically identified siting and permitting concerns with "local communities," "mostly county and township jurisdictions," or "multiple townships and counties." State and local siting and permitting challenges were identified in virtually every state where projects are located, including Virginia, Ohio, Pennsylvania, Maryland, Kentucky, New Jersey, Delaware, West Virginia, and Indiana.

Developers also pointed to regulatory requirements at the state level as major challenges. Several identified the Certificate of Public Convenience and Necessity process in West Virginia as very challenging, particularly given that the state has relatively few areas that are topologically suitable for solar. One developer called out New Jersey's limits on the use of agricultural land for solar arrays.

During the interview process, one developer highlighted what they referred to as "a bit of a chicken and an egg problem—ideally you would time these things so [permitting and construction] would come together, but until you have some kind of certainty that you are going to get an interconnection, we've been unwilling to make massive spending on permitting." Several developers reported that, as a result, they must wait until they receive the ISA before they start the permitting process. This effectively delays the siting and permitting process until the end of the interconnection process instead of conducting these processes in parallel.

Developers also noted that the numerous restudies were leading them to delay both siting and permitting and investment decisions. For example, one developer noted that "PJM likes to think that the interconnection is the last thing that people need, but honestly, when the timelines were better known and adhered to, you could get through the [system impact study], and then you can start making investments, so long as you don't get a surprise in the facilities study phase. But now, you get repeated facilities study delays."

One of the major points that came up across the survey responses is that siting and permitting can be a time-consuming, expensive, and potentially risky investment of funds. As one developer wrote, "state[s] and their associated agencies have competing goals that are not aligned. Local jurisdictional approval[s] are highly subjective and again don't align with intentions and goals." Another noted that a single local siting entity "can tie up project approval through a never-ending appeals process." A different developer identified "litigation of permits" as a key challenge. In each case, developers are having to delay initiating siting and permitting activities.

Relatively few survey respondents for terrestrial projects identified the National Environmental Policy Act or other federal siting or permitting statutes as significant challenges, which likely relates to the fact that federal lands play a smaller role in energy siting decisions in the eastern portion of the United States. During the interview process, several developers did, however, identify concerns about the impact of projects on the habitat of a bat species that had recently been added to the endangered species list.

One offshore wind developer noted that the federal permitting process can propel them to consider alternative points of interconnection or alternative turbine sizes, both of which can trigger a material modification process at PJM, which requires PJM to formally determine whether the change is significant enough to require the generator to restart the interconnection process.

As they put it, the "interconnection process wants a definite design/certainty, while [federal regulators] want flexibility." These developers suggested that better coordination between PJM, FERC, and federal permitting agencies may be warranted. In Europe, by contrast, the Transmission System Operation (the PJM equivalent) identifies points of interconnection at the beginning of the process and starts the permitting process even before the contract is awarded.

Length of Construction Timeline

In general, solar projects appear to be more impacted than fossil projects by long network upgrade construction timelines, potentially because many of the fossil projects involve uprates to existing projects where the interconnection infrastructure largely exists already. While length of construction was cited as a major concern for projects in active development, it was cited far less prominently as a reason for project failure, with only one developer stating that it was a "decisive" reason for a project withdrawal/suspension or pause.

Supply Chain Concerns Unrelated to Solar Tariffs or Import Restrictions

Several developers noted that the length of the interconnection study process was complicating their efforts to address equipment procurement and supply chain issues. Equipment procurement decisions are typically made as late in the construction process as possible to ensure that the project incorporates the most state-of-the-art technology available and to minimize expenses associated with storing equipment. Several developers reported delaying their equipment procurement until after receiving an ISA to avoid the risk of locking in obsolete technology or ordering equipment that they would not be able to immediately deploy. Developers also report that the lack of certainty in interconnection timelines exacerbated their ability to deal with unexpected problems in the equipment pipeline, including as a result of solar tariffs and other pandemic-related supply chain challenges.

Supply Chain Issues Related to Solar Tariffs and Import Restrictions

Respondents were asked to rank the impact of supply chain considerations in general and those related to solar tariffs and import restrictions in particular.[51] When asked to rate the relative impact of all the challenges they previously rated as "major" or "decisive," developers tended to rank tariff/import considerations lower than other challenges, suggesting they were less of a concern than siting and permitting as well as the overall length of the interconnection process. Even firms that ranked tariffs/import considerations as "decisive" said that they were only the third or fourth most significant challenge they faced. Trade issues, however, have the potential to evolve very quickly, and remain a focus for clean energy developers. This shows the complexity of project development and how multiple issues can be decisive to a project's long-term success.

Establishing Site Control

Over the past several years, numerous ISOs and RTOs, including PJM, have ratcheted up site control requirements significantly in an effort to drive down the number of projects in the interconnection queue that have little chance of reaching commercial operation (often colorfully referred to as "zombie projects").

Several developers, whether in their written comments or during the interview process, noted that maintaining site control throughout a lengthy interconnection study process was a challenge. Developers noted that site control is often demonstrated through options agreements, which typically involve an option payment to the property owner, who then agrees not to sell the property to another buyer for a fixed period. Generally, option agreements need to be renewed annually, with larger premiums charged for longer-term tie-ups. Renewing these options can involve expensive and time-consuming negotiations. Solar and wind developers cited site control as a significant challenge, whereas fossil fuel developers did not. As noted above, many of the developers of natural gas-fired projects involve uprates to existing facilities. Because the developer already owns the land on which the existing power plant was sited, they would not experience any issues with site control.

Workforce Issues

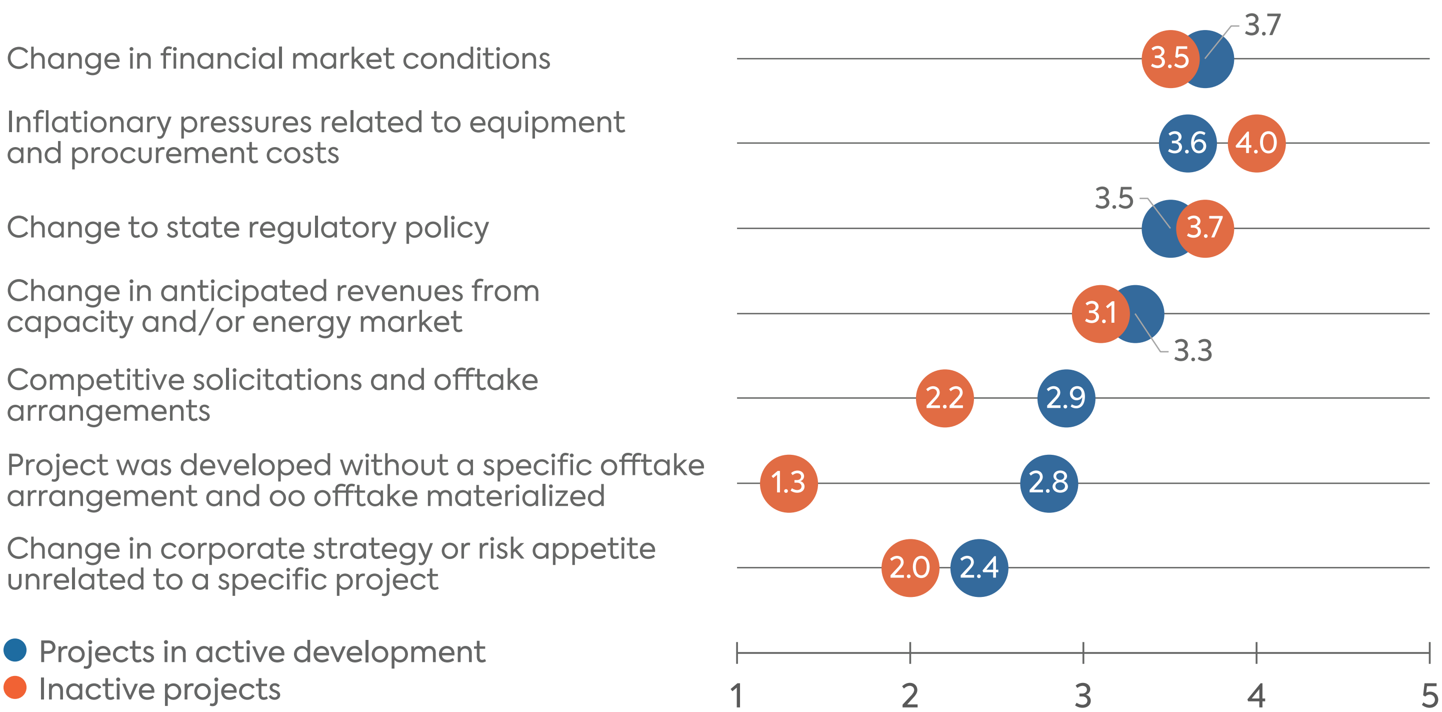
While concerns about workforce Issues were generally not highly ranked, during the interview process several developers referenced Ohio's restrictions on domiciled workers as a key challenge.

Financial and Business Barriers to Project Development

Among the five financial and business barriers included in the survey, respondents identified three as most significant to active and inactive projects alike: changes to financial market conditions, inflation-driven increases in equipment procurement costs, and changed outlook on state incentives. They deemed the two remaining challenges—absence of an offtake agreement and changes in corporate strategy or risk appetite—as less impactful, though more important for projects in active development than for inactive projects (Figure 7).

Figure 7: Average ratings on a five-point scale (5 = decisive impact, 1 = no impact) of financial and business barriers to both projects in active development and inactive projects, based on 19 respondents for active projects and 13 for inactive projects

"Thinking about your projects that are {inactive / actively in development}, please rate the following factors associated with project finance or economics on {your decision(s) / how much of a challenge they are to the project(s)}"



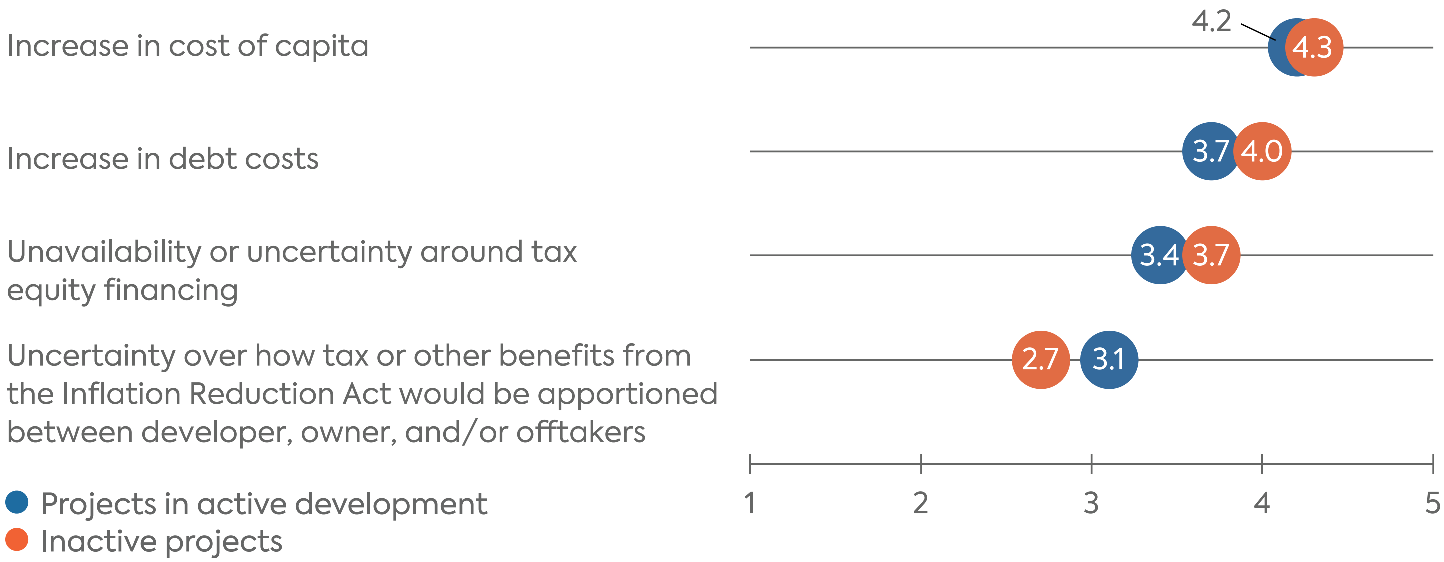
Note: The "Inactive" category includes projects that PJM has withdrawn from its queue or put into suspension, or that a firm has paused or ceased development on.
Source: Authors' analysis.

Change in Financial Market Conditions Related to Cost of Capital, Financing, Tax Equity, or Other Financing Metrics (Separate from Equipment Procurement Costs)

Developers identified changes in financial market conditions related to cost of capital, tax equity, and other financing metrics as a top concern for both active and canceled or paused projects, suggesting that macroeconomic factors related to cost of capital are top of mind for developers. One developer also identified access to tax equity as a significant challenge.

Respondents were also asked to rate four financial market conditions on the same five-point scale for both active and canceled or suspended (Figure 8).

Figure 8: Average ratings on a five-point scale (5 = decisive impact, 1 = no impact) for impact of financial market conditions on active and inactive projects, based on 11 respondents for active projects and 4 respondents for inactive projects



Source: Authors' analysis.

Notably, developers of natural gas-fired projects ranked changing financial conditions fourth, behind state incentives policies, changes in anticipated energy and capacity revenues, and inflationary pressure on equipment, likely reflecting the longer development timeframes associated with fossil units.

Inflationary Pressures Related to Equipment Procurement Costs

Inflationary pressures on equipment procurement were identified as a significant challenge to projects in active development and as a predominant cause of the suspension, pausing, or withdrawal of inactive projects, with approximately three-fourths of respondents citing inflation as the most severe challenge their projects faced. Solar developers rated this issue as slightly less significant than did developers of natural gas-fired and wind generation resources. This discrepancy may reflect the fact that steel and other commodities greatly affected by inflation over the past several years are a larger component of wind turbine and natural gas projects than they are of solar projects.

Change to State Regulatory Policy that Affected the Value of Environmental Attribute or Incentive Programs

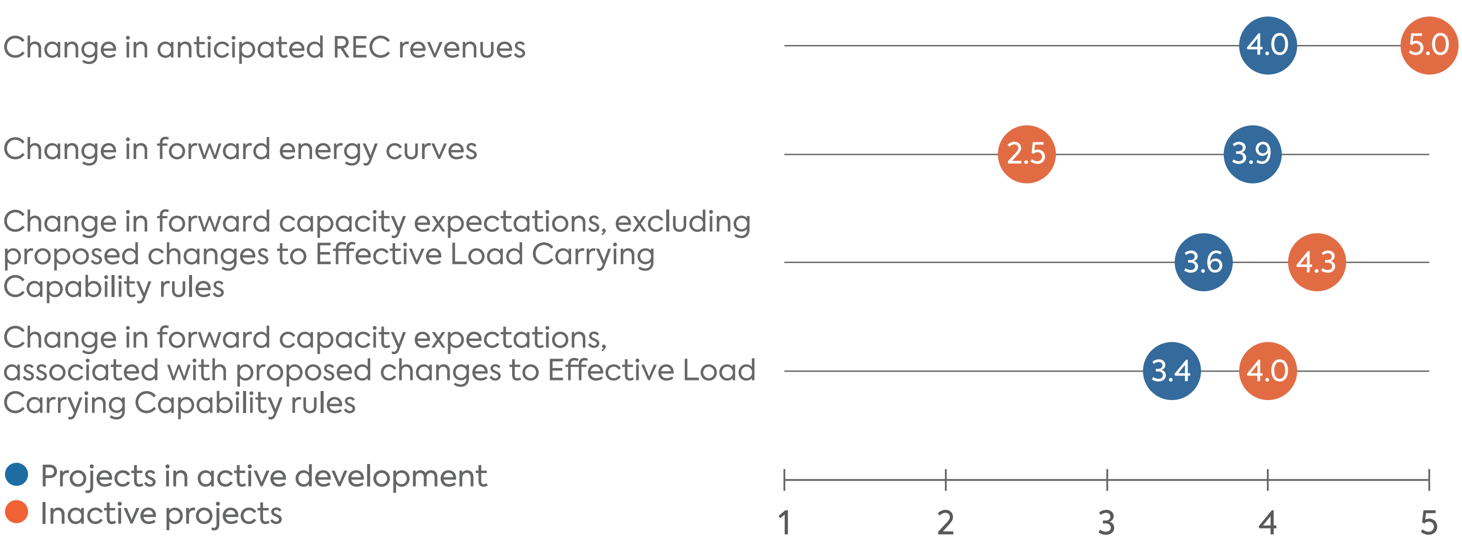
Fossil fuel developers identified state policies as "decisive," likely because of the impact of those policies on new renewable generation, which could have a depressive effect on energy and capacity market revenues. Solar developers appeared to be less concerned with changes to state incentive policies, giving it an average score of 2.8 out of 5, suggesting that they are either comfortable with the regulatory risk associated with solar incentives or are successfully hedging that risk through their sales of environmental attributes of power purchase agreement structures.

Change to Anticipated Revenues from the Capacity and/or Energy Market

Solar and wind developers appeared less concerned about changes to wholesale market revenues, giving it an average score of 3.1 out of 5, perhaps because they are utilizing power purchase agreements or other contractual structures to minimize exposure to fluctuations in wholesale revenues. If so, these results suggest that relatively few solar projects are built on a merchant basis, and that capacity makes up a smaller slice of total project revenues than it does for natural gas facilities.

Firms identifying wholesale revenues as "major" or "decisive" impacts were asked to rate on the same five-point scale a series of factors related to future revenue expectations (Figure 9).

Figure 9: Average ratings on a five-point scale (5 = decisive impact, 1 = no impact) of the importance of changes in anticipated revenues from the capacity and energy markets to projects, based on responses from 8 developers with active projects and 3 with inactive projects



Source: Authors' analysis.

Solar developers (who comprised a significant portion of the pool) were nearly evenly divided between the four options. Developers of natural gas-fired generation resources identified forward energy curves as the most significant factor, which comports with the general expectation that natural gas resources earn most of their revenue from the energy market. The second most significant factor for these fossil developers was capacity market expectations (excluding changes in ELCC rules), followed by changes in anticipated REC revenues and ELCC-driven capacity market changes.

Competitive Solicitations and Offtake Arrangements

Respondents were asked to address their experiences with offtake arrangements in two separate questions, one focused on competitive solicitation processes and the other on whether they developed projects without a specific offtake arrangement in place.

In general, the ability to win a competitive solicitation or comparable process received an average score of 2.9 out of 5, with the small number of wind developers rating this challenge significantly higher (4.3 out of 5) than solar (2.3 out of 5) or natural gas developers (2.0 out of 5). Rankings for the question about offtake arrangements were similar, with an average score of 2.8 out of 5, and a similar trend between technology types.

Two developers indicated that the lack of a specific offtake arrangement was a “decisive” factor in their project development plans. An additional developer indicated that lack of offtake was a “major” factor, while the remaining developers ranked this issue lower. One developer identified the inability to win a competitive solicitation as a “major” reason for the suspension, withdrawal, or pausing of a project. However, the relatively small number of developers who identified lack of offtake or inability to win a competitive solicitation tended to regard that challenge as a significant barrier (either the biggest or the second biggest).

The binary ratings on this topic are likely the result of differing business risk appetites. Developers who highlighted challenges associated with arranging an offtake agreement or winning a competitive solicitation also tended to rate changes in forward energy curves as significant issues. This suggests that, similar to fossil developers, developers with more merchant exposure were more concerned about long-term energy price forecasts. Natural gas developers also fall into this category, since they typically develop on a merchant basis and do not rely on offtake agreements

Change in Corporate Strategy or Risk Appetite Unrelated to a Specific Project

One developer stated that changes in corporate strategy or risk appetite represented a "major" issue for their development efforts, while a separate developer cited this factor as a "major" reason for the cancellation of one or more projects. However, this view was not widely shared, as most developers across technology classes rated this challenge as having "no," a "small," or a "moderate" impact on their development efforts.

Interconnection Upgrade Costs

While the survey did not focus on interconnection upgrade costs, eight of the 15 developers that reported withdrawing, suspending, or pausing one or more projects cited interconnection upgrade costs as a key issue.

Outlook on Future Development Efforts

Unlike other questions that focused on existing projects under development, this section of the survey asked about the developer's general outlook on development. Provided a list of potential issues that included solar tariffs and supply chain constraints, developers were asked, "Thinking about 12 months into the future, which of these factors do you anticipate will continue to negatively affect your development efforts?" The summary of the responses is in Table 3.

Table 3: Percentage of respondents who identified factors anticipated to negatively affect future development efforts, based on 16 total responses

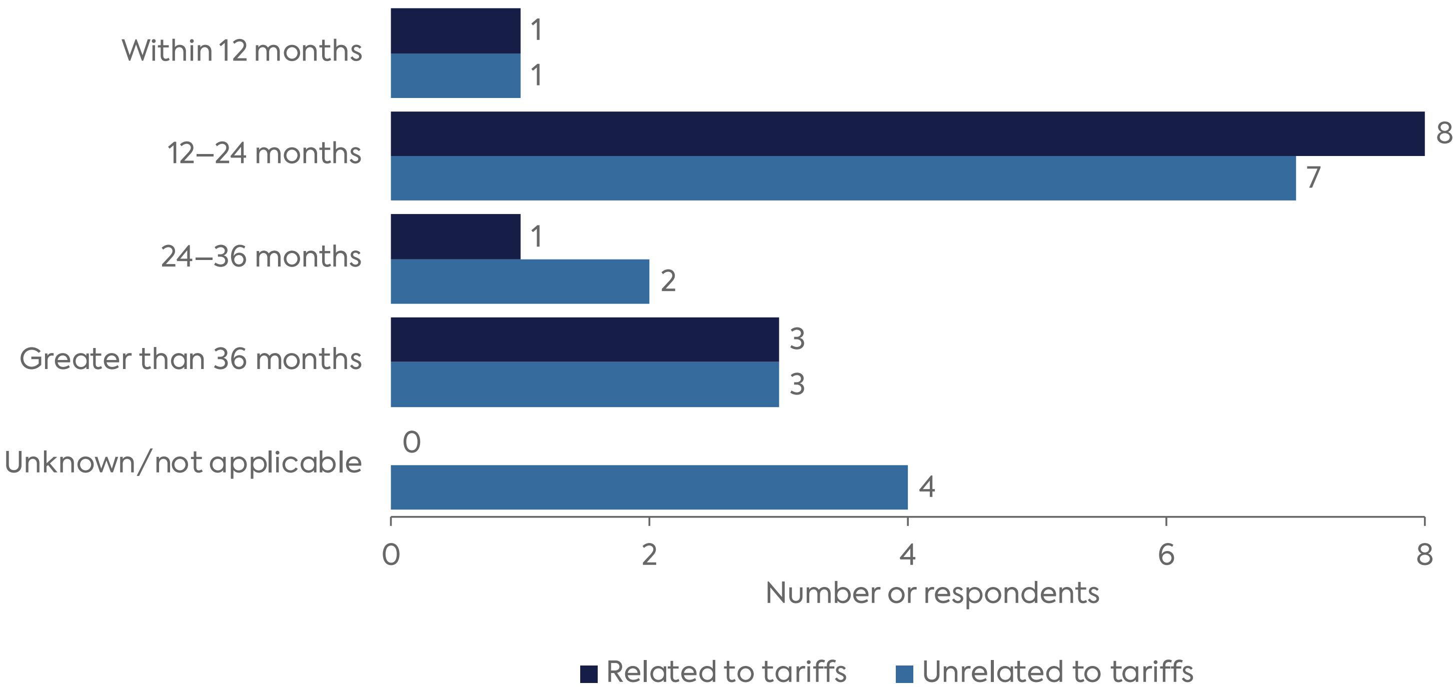
Factor	%
Length of the construction timeline for network upgrades or interconnection facilities or uncertainty around that timeline.	90%
Supply chain concerns unrelated to solar tariffs or import restrictions	81%
Siting or permitting considerations at the federal, state, or local level	57%
Inflationary pressures related to equipment procurement costs	57%
Change in financial market conditions related to cost of capital, financing, tax equity, or other financing metrics (separate from equipment procurement costs)	57%
Length of construction timeline for network upgrades or interconnection facilities or uncertainty around that timeline	57%
Supply chain concerns related to solar tariffs or import restrictions	43%
Change to state regulatory policy that affected value of environmental attribute or incentive programs	38%
Change in anticipated revenues from the capacity, energy, and/or REC market	29%
Ability to establish site control	24%
Other, please describe	19%
Ability to win a competitive solicitation or comparable process	14%
Potential inability to line up an off-take arrangement	14%
Reallocation of resources to another project	14%
Change in corporate strategy or risk appetite unrelated to a specific project	14%

In their outlook for the year ahead, developers expressed many of the same concerns they expressed for past periods, with interconnection timelines continuing to be at the top of the list, followed by macroeconomic factors such as supply chain and cost of capital as well as network upgrade construction timelines and siting and permitting. Several developers called out interconnection costs, pressure from PJM around milestone dates, availability of labor for equipment procurement and construction, and the prospect that high demand for skilled labor could result in higher costs.

In response to the question "When do you estimate that supply chain issues for solar panels {*related*

/ not related} to solar tariffs are likely to be resolved?," most respondents estimated 12–24 months, though nearly a quarter stated "unknown" or "not applicable" when considering issues unrelated to tariffs (Figure 10).

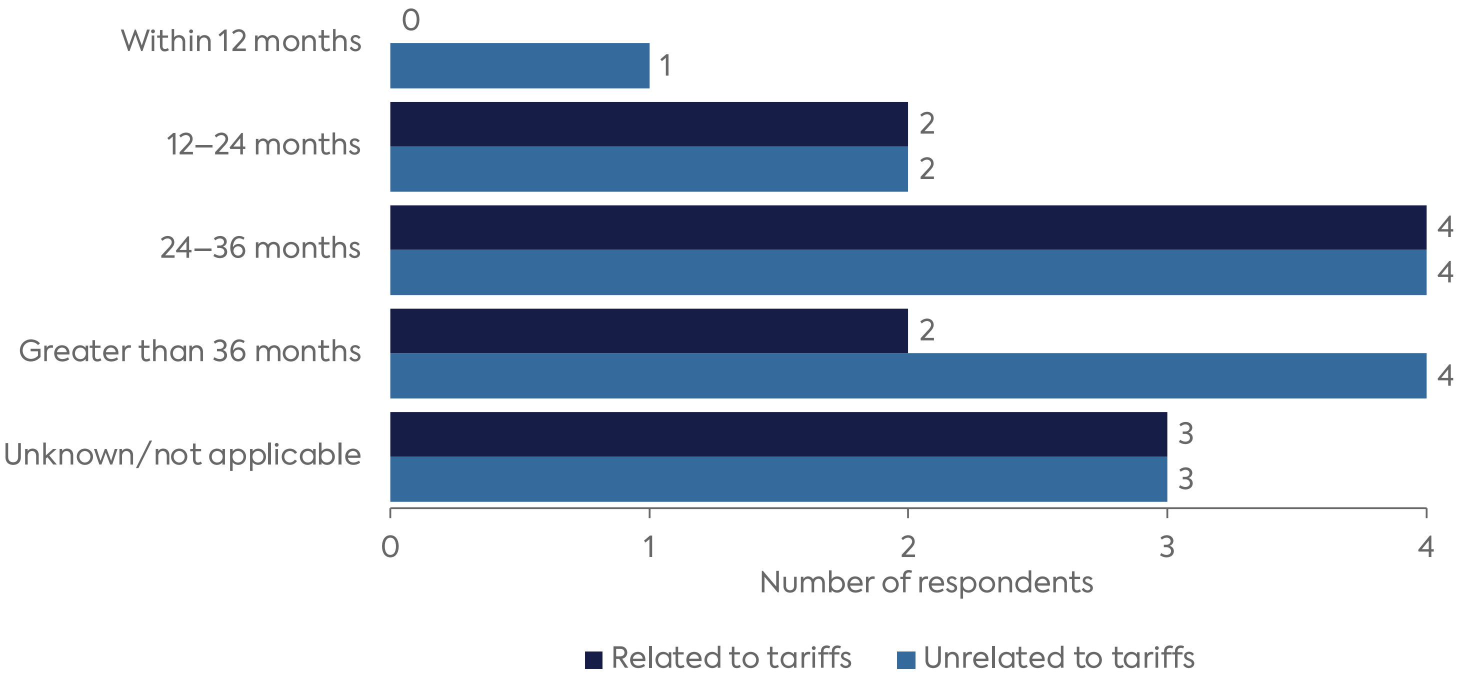
Figure 10: Estimated timeframe for solar panel supply chain issues to be resolved, based on 17 responses.



Source: Authors' analysis.

Developers have also struggled with supply chain issues limiting the availability of transformers. In response to the question "What is your outlook on when supply chain issues for transformers or other issues {*related / not related*} to solar tariffs are likely to be resolved?," developers expressed that, unlike supply chain issues related to solar panels, they expect it will take a long time, with approximately 30% saying either 24–36 or more than 36 months and only one saying within 12 months (Figure 11).

Figure 11: Estimated timeframe for supply chain issues related to transformers to be resolved, based on 14 responses.



Source: Authors' analysis.

During the interview process, several developers noted that it is typically the utility's responsibility to procure high-voltage breakers and transformers. One developer noted that it was currently taking transmission owners over two years to procure high-voltage circuit breakers, and they had recently been told that procuring a 345 kilovolt circuit breaker would take four years in another market region. The data reflect this pessimism, with developers reporting extended delays in transformer supply.

Conclusion

The idea that the interconnection process is fundamentally broken is not new. Nor is the idea that additional reforms will be necessary to fix the process.[52] Interconnection delays are fundamentally caused by a transmission grid that is not sized to meet the amount of new clean generation that is being brought to market and an overly lengthy process for identifying how to grow the grid.

The survey highlights that stakeholders, including PJM, may need to adjust their expectations of how quickly new generation resources can come online. Developers report that most of their projects will take two or more years to reach commercial operation, even after they complete the interconnection process. Survey respondents repeatedly highlighted the pernicious interplay between interconnection delays and siting and permitting challenges—in particular, the fact that site-specific permits and siting approvals expire after a period of inactivity that is typically shorter than the interconnection queue process. Further, the wide range of potential interconnection study times is leading developers to delay high-risk siting and permitting activities,[53] which can be the most contentious and risky part of the development process, until the end of the study process, potentially adding years to commercial operation timelines. This is a troubling sign, suggesting that delays and project cancellations will continue to occur at high levels for the foreseeable future.

This lengthy timeline also underlines the role that interconnection plays in PJM's competitive markets. New generation has the power to displace more expensive resources and discipline the exercise of supply-side market power. But Interconnection queue delays blunt the ability of PJM to ensure effective competition in its markets since even relatively inefficient generators (or those exercising market power) are more difficult to displace with new, lower-cost resources.

Solving the interconnection crisis will likely require two changes: creating effective planning processes that identify where new transmission headroom is likely to be needed; and expanding the transmission system to meet that need. The path to a transmission grid that is "fit for purpose" is long, however, involving difficult questions around cost causation and allocation. PJM is currently considering reforms to its long-range transmission planning process, which lags behind that of other regions in the US.[54] The new reforms are designed to identify proactively the transmission needed to meet future queue needs and address the reliability needs of the grid.[55] FERC is also expected to issue a regional transmission rule in the near future focused on transmission planning reforms on the national level.[56]

Beyond these measures, a significant overhaul of interconnection processing policies will likely be needed. FERC's recent interconnection reforms in Order No. 2023 are an important step forward but are unlikely to fully resolve the problem.[57] FERC may want to consider a range of fixes, from technical reforms that can increase access to the grid in the short term[58] to wholesale revisions to the existing interconnection study framework.[59] Given the immediate needs of the grid, interconnection solutions will likely need to be pursued in parallel with longer-term grid reform efforts. Some that policymakers may wish to consider include:

- Allowing retiring generators to be replaced with new resources at the same location.[60]
- Increasing the use of advanced technologies, such as Grid Enhancing Technologies, that allow more power to flow over existing transmission lines.[61]
- Transitioning from today's study-intensive "invest and connect" model to a study-light "connect and manage" model.[62]

State regulators and other policymakers will also be wise to manage the phaseout of existing resources carefully. One way of doing so is to build "reliability safety valves" into environmentally driven retirement schedules. This safety valve could dynamically adjust retirement dates based on PJM's expected reserve margin or success in bringing on replacement generation. While the PJM market structure sends higher price signals during times of supply scarcity to attract new resources, there may be a lag in new entry, particularly given the lengthy interconnection process.

Notes

1. Joseph Rand et al., "Queued Up: 2024 Edition – Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023," Lawrence Berkeley National Laboratory, April 2024, https://emp.lbl.gov/publications/queued-2024-edition-characteristics; and Joseph Rand et al., "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2022," Lawrence Berkeley National Laboratory, April 2023, https://doi.org/10.2172/1969977.

2. Federal Energy Regulatory Commission, "Order No. 2023: Improvements to Generator Interconnection Procedures and Agreements," 184 FERC ¶ 61,054 (2023) at P 39–40, https://www.ferc.gov/media/order-no-2023 (finding that "[f]or generating facilities built in 2022, wait times in the interconnection queue saw a marked increase to now roughly five years").

3. See FERC, Order No. 2023 at P 49 (noting that "a withdrawal can trigger costly restudies and create uncertainty in the interconnection process for interconnection customers and transmission providers alike").

4. Rand et al., "Queued Up: 2024 Edition" (noting that PJM completed zero interconnection service agreements in 2023).

5. See PJM, "Energy Transition in PJM: Resource Retirements, Replacements & Risks," February 24, 2023, 2, https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

6. See, e.g., Claire Wayner et al., "Going the Distance on Interconnection Queue Reform: FERC's Rulemaking Takes Us Only Part of the Way to Effective and Efficient Interconnection," RMI, August 2023, https://rmi.org/going-the-distance-on-interconnection-queue-reform/; Robi Nilson, Ben Hoen, and Joseph Rand, "Survey of Utility-Scale Wind and Solar Developers Report," Lawrence Berkeley National Laboratory, January 2024, https://emp.lbl.gov/publications/survey-utility-scale-wind-and-solar (finding that, on a national basis, interconnection delays were the second biggest cause of canceled projects and the biggest driver of delays.

7. See, e.g., Nilson et al., "Survey of Utility-Scale Wind and Solar Developers Report."

8. As FERC notes, "backlogs in the generator interconnection process, in turn, can create reliability issues as needed new generating facilities are unable to come online in an efficient and timely manner." FERC, Order No. 2023 at P 3. See also Monitoring Analytics, "2023 State of

the PJM Market Report," 2024, 1, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023/2023-som-pjm-sec1.pdf. ("The markets face a challenge from potentially high levels of expected thermal generator retirements, with no clear source of replacement capacity or the fuel required for that capacity.")

9. See Rand et al., "Queued Up: 2024 Edition."
10. Ibid., 3.
11. FERC, Order No. 2023.
12. See, e.g., Jesse D. Jenkins et al., "Mission Net-Zero America: The Nation-Building Path to a Prosperous, Net-Zero Emissions Economy," *Joule* 5, no. 11 (2021), https://doi.org/10.1016/j.joule.2021.10.016.
13. FERC, Order No. 2023.
14. For detailed background about PJM's efforts to fix its queue, see PJM Interconnection LLC, 181 FERC ¶ 61,162 (2022), footnote 15, https://pjm.com/directory/etariff/FercOrders/6581/20221129-er22-2110-000%20and%20-001.pdf.
15. PJM Interconnection LLC, 181 FERC ¶ 61,162 (2022) at P 57.
16. Monitoring Analytics, "2023 State of the Market Report," 74.
17. Ibid., 74.
18. Ibid., 75.
19. Ibid., 75.
20. PJM, "New Interconnection Process Reaches Next Milestone," press release, December 21, 2023, https://insidelines.pjm.com/new-interconnection-process-reaches-next-milestone/.
21. See PJM, "Energy Transition in PJM."
22. Ibid., 17.
23. Monitoring Analytics, "2023 State of the Market Report," 1.
24. PJM, "Energy Transition in PJM," 13.
25. See PJM, "Update on Reliability Risk Modeling," May 30, 2023, https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230530/20230530-item-03---reliability-risk-modeling.ashx.

26. Mark Specht's primer "ELCC Explained: The Critical Renewable Energy Concept You've Never Heard Of," is an excellent resource for understanding capacity accreditation. Union of Concerned Scientists, 2020, https://blog.ucsusa.org/mark-specht/elcc-explained-the-critical-renewable-energy-concept-youve-never-heard-of/.

27. See PJM's report detailing extensive outages of fossil resources during December 2022 Winter Storm Elliott weather event: https://pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx.

28. See PJM, "Energy Transition in PJM," 8.

29. Ibid., 5.

30. Monitoring Analytics, "2023 State of the Market Report," 1.

31. See PJM, "Energy Transition in PJM," 7.

32. For a detailed description of the statute, including reference emissions rates, see https://epa.illinois.gov/topics/ceja/electric-generating-units.html.

33. See PJM, "Energy Transition in PJM," 8.

34. Ibid., 6, figure 2.

35. PJM's commercial probability model suggests that less than 10% of the projects starting the interconnection process are expected to actually reach commercial operation and suggests that "after adjusting the new renewable capacity by Effective Load Carrying Capability (ELCC) derations, this commercial probability analysis estimates net 13.2 GW-nameplate / 6.7 GW-capacity to the system by 2030." See PJM, "Energy Transition in PJM,"12.

36. The PJM Energy Transition Report's High New Entry Scenario included "107 GW-nameplate/30.6 GW-capacity after ELCC derations. Net natural gas entry was approximately 5 GW, and renewables was 48.5 GW-nameplate/10.4 GW-capacity."

37. PJM, "New Interconnection Process Reaches Next Milestone."

38. See Letter from Ohio Manufacturers Association, December 21, 2023, https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20231221-oh-manufacturers-assoc-letter-re-competitive-electricity-markets-during-rapid-system-technological-transformation.ashx; and James F. Wilson, "Maintaining the PJM Region's Robust Reserve Margins," National Resources Defense Council and Sierra Club, May 2023, (https://www.sierraclub.org/sites/www.sierraclub.org/files/2023-05/Wilson%20R4%20Report%20Critique%20Revised.pdf.

39. A small subset of projects in the study window received Wholesale Market Participation Agreements in lieu of an Interconnection Services Agreement, but are effectively the same for the purposes of our study.

40. "Uprates" are when an already-existing facility requests that PJM formally increase the maximum sustained output for the facility. Uprates are usually occasioned by improvements in power plant efficiency, changes in fuel type, or operational experience that justifies a higher output level.

41. PJM," Services Request Status," https://www.pjm.com/planning/service-requests/services-request-status.

42. Several developers self-identified as having more projects that appear in the queue. Because these were likely data entry errors or a misunderstanding of the question, we manually adjusted several of the numbers to bring them into line with what appears in the queue.

43. See Sarah Johnston, Yifei Liu, and Chenyu Yang, "An Empirical Analysis of the Interconnection Queue," National Bureau of Economic Research working paper, December 2023, https://doi.org/10.3386/w31946 (finding that they were able to identify developers for 39% of overall entrants into the PJM interconnection queue increasing to 52% and 81% of projects that had advanced further through the interconnection process).

44. The full survey instrument is available for download on the Center on Global Energy Policy website.

45. While PJM's Energy Transition Report focused on the reliability implications of reserve margins below 10%, low reserve margins typically lead to steeply increasing consumer costs, which could have major implications for energy affordability, even if grid reliability isn't compromised. See PJM, "Energy Transition in PJM," 15.

46. Ohio law requires that developers of most energy projects qualify for advantageous tax treatment if they receive the support of local government and employ a certain percentage of workers domiciled in Ohio. Section 5727.75, "Exemption on Tangible Personal Property and Real Property of Certain Qualified Energy Projects." For a summary of the implications of Ohio's siting rules, see https://www.bricker.com/Documents/Resources/QEP%20_project_white_paper.pdf.

47. For example, the Solar Energy Industries Association suggests that a typical large (250 MW) project takes approximately two years to construct after completion of the interconnection study process, construction of network upgrades, siting, permitting, and other necessary

steps. SEIA, "Development Timeline for Utility-Scale Solar Power Plant," https://www.seia.org/research-resources/development-timeline-utility-scale-solar-power-plant.

48. FERC recently approved a variety of changes to PJM's interconnection rules, including requiring developers to include deposits with their interconnection requests and to demonstrate that the project met certain project maturity requirements, e.g., demonstrating site control. These deposits are designed to ensure that developers are willing to post financial security behind their development efforts and reduce the incidence of speculative or low-probability projects.

49. Emma Penrod, "Why the Energy Transition Broke the US Interconnection System," Utility Drive, August 22, 2022, https://www.utilitydive.com/news/energy-transition-interconnection-reform-ferc-qcells/628822/.

50. In an analysis of the PJM queue, Johnston et al. suggest that the low concentration of projects among developers counters assertions that speculative interconnection requests are burdening queue processing. They find that in "cases where a developer had more than one generator in an entry cohort, either all or none of the generators were completed 71% of the time," and that "these data are generally consistent with developers being willing to build all generators that are individually profitable." Johnston et al., "An Empirical Analysis of the Interconnection Queue."

51. For a summary of solar tariff and import issues, see Lilly Yejin Lee and Noah Kaufman, "Q&A: Solar Tariffs and the US Energy Transition," Energy Explained, Center on Global Energy Policy, November 13, 2023, https://www.energypolicy.columbia.edu/qa-solar-tariffs-and-the-us-energy-transition/.

52. See, e.g., Comments of FERC Commissioner Allison Clements at the Raab Associates' New England Electricity Restructuring Roundtable on Dec. 8, *available at*: https://www.rtoinsider.com/65517-clements-raab-roundtable/.

53. See, e.g., Nilson et al., "Survey of Utility-Scale Wind and Solar Developers Report."

54. See Lewis (Zhaoyu) Wu, Abraham Silverman, Harrison Fell, and James Glynn, "A Quantitative Analysis of the Impact of Key Variables on Power Transmission Infrastructure Project Development in the US," Center on Global Energy Policy, Columbia University, April 5, 2024, https://www.energypolicy.columbia.edu/publications/a-quantitative-analysis-of-variables-affecting-power-transmission-infrastructure-projects-in-the-us/ (showing that transmission expansion in PJM has lagged behind several other regions).

55. See PJM's Long-Term Regional Transmission Planning initiative, https://www.pjm.com/

committees-and-groups/workshops/ltrtp.

56. See Federal Energy Regulatory Commission, "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," 179 FERC ¶ 61,028 (2022).

57. Silverman, et al., "FERC's Interconnection Reform: Why It Matters for the Clean Energy Transition," Energy Explained, Center on Global Energy Policy, August 7, 2023, https://www.energypolicy.columbia.edu/fercs-interconnection-reform-why-it-matters-for-the-clean-energy-transition/.

58. See, e.g., RMI, "Clean Repowering: How to Capitalize on Fossil Grid Connections to Unlock Clean Energy Growth," January 2024, https://rmi.org/insight/clean-repowering.

59. See, e.g., Tyler Norris, "Beyond FERC Order 2023: Considerations on Deep Interconnection Reform," Nicholas Institute for Energy, Environment & Stability, Duke University, August 2023, https://nicholasinstitute.duke.edu/publications/beyond-ferc-order-2023-considerations-deep-interconnection-reform.

60. See, e.g., RMI, "Clean Repowering."

61. See, e.g., WATT Coalition, "Grid Enhancing Technologies in Generator Interconnection," https://watt-transmission.org/grid-enhancing-technologies-in-generator-interconnection/; and Russell Mendell, Mathias Einberger, and Katie Siegner, "FERC Could Slash Inflation and Double Renewables with These Grid Upgrades," RMI, July 7, 2022, https://rmi.org/ferc-could-slash-inflation-and-double-renewables-grid-upgrades/.

62. "Under the "connect and manage" model, the grid operator narrows the scope of the interconnection study process to look at the grid enhancements necessary to allow the generator to physically interconnect to the grid. Questions around deliverability of the power are deferred to subsequent studies. This reduces the complexity of the interconnection process, resulting in faster studies and increased ability to process interconnection requests. In exchange, interconnecting generators accept higher congestion and curtailment risk until deliverability studies and necessary upgrades are completed." See Silverman et al., "What's Next in Interconnection Reform? Lessons from International Experience," Energy Explained, Center on Global Energy Policy, August 15, 2023, https://www.energypolicy.columbia.edu/whats-next-in-interconnection-reform-lessons-from-international-experience/; see also Tyler Norris, "Beyond FERC Order 2023."

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CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing document to be served upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated on this 17th day of October, 2024.

/s/ Peter J. Hopkins
Peter J. Hopkins

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